THE COMMONWEALTH OF MASSACHUSETTS
THE DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

D.T.E. 05-27

INITIAL BRIEF OF BAY STATE GAS COMPANY

IN SUPPORT OF BAY STATE GAS COMPANY'S REQUEST FOR AN INCREASE IN BASE REVENUE AND OTHER RATE MODIFICATIONS

BAY STATE GAS COMPANY

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I. INTRODUCTION

Bay State Gas Company ("Bay State" or the "Company") seeks new base rates in order to allow it the opportunity to recover the costs it incurs to serve its customers and to earn a reasonable rate of return on its investment in local distribution operations during the first year new rates will be in effect, the period December 1, 2005 through November 30, 2006 ("rate year"). This filing is the first comprehensive base rate filing made by Bay State since 1992. Bay State Gas Company, D.P.U. 92-111 (1992) (full base rate proceeding). A relatively small base rate increase was granted for Bay State in 1997. Bay State Gas Company, D.T.E. 97-97 (1997) (limited settled proceeding allowing step adjustment to rates to accommodate specific capital programs; did not include a base rate increase for other purposes).

In this proceeding, Bay State seeks an additional rate adjustment (included in its proposed Annual Base Rate Adjustment Mechanism, or "ABRAM") associated with an accelerated level of capital investment made because of its need for major capital improvements to enhance system reliability and to meet federal and state safety requirements relative to its aging and deteriorated bare steel and non-cathodically protected coated steel infrastructure (the Steel Infrastructure Replacement, or "SIR," program). This filing also requests approval of a pension and postretirement benefits other than pensions ("PBOP") adjustment mechanism. The proposed rates for Bay State will establish the cast-off rates for Bay State's five (5)-year Performance Based Regulation ("PBR") plan filed in this proceeding. Exh. BSG/JES-1, pp. 6 - 7.

The requested base rate increase is needed to support increases in net plant investment since Bay State's last base rate proceeding 13 years ago. D.P.U. 92-111. The most significant growth in the Company's investments has been for gas main replacements, non-revenue producing safety and reliability improvements and information technology, including customer information system upgrades and replacements required to meet Year 2000 concerns. The proposed rates also reflect increases in the Company's operating costs, including employee wages and benefits, insurance, property taxes, depreciation and other normal business expenses during a period when overall customer usage and revenue growth for natural gas has been flat or declining.

Since 1992, Bay State has demonstrated its ability to manage its business to avoid base rate increases. In fact, overall, the operating and maintenance expense portion of Bay State's rates is less now than it was 13 years ago. However, the combination of rising operating costs, the need for major capital additions, and the declining growth in sales and revenues, requires Bay State to seek a base rate adjustment and associated ABRAM now.

Bay State has supported its request for a base rate increase with a comprehensive case presented by both internal and external expert witnesses. In addition, Bay State responded to over 1,900 information and record requests from the Massachusetts Department of Telecommunications and Energy (the "Department") and the intervening parties. The Company presented nine (9) witnesses during twenty-five (25) days of evidentiary hearings. Many components of the Company's filing were uncontested. Bay State's rate filing is consistent with Department precedent and responsive to Department directives and reflects the reality of the economic environment in which Bay State operates.

Bay State's proposed rates are just and reasonable and are fully supported by a complete evidentiary record.

II. PROCEDURAL HISTORY

Pursuant to G.L. c. 164, sec. 94, and 220 C.M.R. 5.00, Bay State filed revised rates and charges for gas service with the Department on April 27, 2005, to be effective June 1, 2005 (rate schedules M.D.T.E. Nos. 34 – 68); Exh. BSG-Tariffs. Bay State's filed rates were designed to produce increased total annual revenues from the currently effective base rates in the amount of $22,238,326, based upon a test year that ended December 31, 2004. Exh. BSG/JES-1, Sch. JES-1. The requested increase represents an overall increase of approximately 4.7% in Bay State's total gas revenues. The Department docketed its investigation of Bay State's proposed rates as D.T.E. 05-27.

Bay State submitted the prefiled testimony of nine (9) witnesses, together with related supporting schedules, studies and workpapers. Bay State's witnesses in this proceeding are: (1) Stephen H. Bryant, President of Bay State since 2003 (Exh. BSG/SHB-1 through Exh. BSG/SHB-4); (2) Danny G. Cote, Bay State's General Manager (Exh. BSG/DGC-1 through Exh. BSG/DGC-11); (3) John E. Skirtich, an expert consultant on Bay State's revenue requirements (Exh. BSG/JES-1 through Exh. BSG/JES-6); (4) Steven A. Barkauskas, Vice President of Total Rewards for NiSource Corporate Services Company, supporting wage, payroll and benefits adjustments and analyses (Exh. BSG/SAB-1 through Exh. BSG/SAB-2); (5) Joseph A. Ferro, Bay State's Manager, Regulatory Policy, on revenues, rate design and tariff issues (Exh. BSG/JAF-1 through Exh. BSG/JAF-3); (6) Earl M. Robinson, an expert consultant from AUS Consultants on depreciation (Exh. BSG/EMR-1 through Exh. BSG/EMR-2); (7) Paul R. Moul, an expert consultant on return on equity (Exh. BSG/PRM-1 through Exh. BSG/PRM-2); (8) Dr.

Lawrence R. Kaufmann, an expert consultant from Pacific Economics Group LLC on Bay State's proposed performance based regulation plan (Exh. BSG/LRK-1 through Exh. BSG/LRK-2); and (9) James L. Harrison, an expert consultant from Management Applications Consulting, Inc., on Bay State's allocated cost of service studies and marginal cost study (Exh. BSG/JLH-1 through Exh. BSG/JLH-3).

By Order of the Department, dated April 28, 2005, the effective date of Bay State's proposed rates was suspended until December 1, 2005. The following hearings for public comment were promptly scheduled and held: for Bay State's Springfield Division, the public hearing was held on May 25, 2005 in Ludlow, Massachusetts; for Bay State's Lawrence Division, the public hearing was held on May 31, 2005 in Andover, Massachusetts; and, for Bay State's Brockton Division, the public hearing was held on May 26, 2005 in Brockton, Massachusetts.

The Massachusetts Attorney General ("Attorney General") filed a Notice of Intervention on May 6, 2005. The Massachusetts Division of Energy Resources ("DOER") filed a Petition to Intervene on May 26, 2005. In addition to the Attorney General and DOER, the following entities sought and were granted full intervenor status at the procedural conference held in Boston on June 2, 2005: Massachusetts Association for Community Action ("MASSCAP") (based on its motion dated May 24, 2005); MassPower (based on its motion dated May 27, 2005); United Steelworkers of America ("USWA") (based on its motion dated April 28, 2005); Local 273, Utility Workers Union of America ("UWUA") (based on its motion dated May 17, 2005); Massachusetts Oilheat Council ("MOC") (based on its motion dated May 17, 2005);

NSTAR Gas Company, Boston Edison Company, Cambridge Electric Light Company and Commonwealth Electric Company (the “NStar Companies” or “NStar”) (based on its motion dated May 26, 2005); and Boston Gas Company d/b/a KeySpan Energy Delivery of New England (“KeySpan”) (based on its motion dated May 26, 2005).[1] Certain additional entities were granted limited participant status at the procedural conference: New England Gas Company; Berkshire Gas Company; Western Massachusetts Electric Company; Massachusetts Electric Company; and Fitchburg Gas and Electric Light Company d/b/a Unitil.

A significant number of prehearing motions and appeals of Hearing Officer orders were filed by the Attorney General: Motion to Conduct Depositions (denied by the Department on July 1); Motion to Bifurcate the proceeding and move the pension mechanism, the steel infrastructure replacement program (“SIR program”) and the PBR plan into one or more separate proceedings (moot); a Motion for Leave to submit additional argument on the denied motions; Appeal of the rulings permitting certain parties full party status; a Motion for Oral Argument; Motion for leave to enter Bay State’s property (mooted when Bay State offered a site visit for viewing and a facilities tour); an Appeal of the procedural schedule; a Motion to Compel Discovery (for 2 responses out of 1,599 information requests) (moot); Motion for Leave to Submit Additional Argument (moot). The Attorney General also opposed the inclusion of 2005 SIR expenses as a post-test year adjustment.

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[1] MASSCAP and MassPower did not present witnesses, participate in cross-examination or file initial briefs in the case.

In Bay State's view, each of these motions and appeals was unnecessary, served to delay the proceeding unnecessarily, and required the expenditure of considerable time and effort by the Company, the Department and other parties. Many of the issues raised in the motions could well have been resolved without Department involvement if the Attorney General engaged in further good faith discussions with the Company to resolve the issues that were the subjects of the motions.

In addition, the UWUA filed a Motion to Preserve the Status Quo, that became moot following the voluntary agreement by the Company to maintain its staffing levels until the conclusion of this rate proceeding.

The Attorney General presented four witnesses: David J. Effron on revenue requirements (Exh. AG-9); Jacob Pous on depreciation (Exh. AG-6); Jon R. Cavallo on the Company's steel infrastructure replacement program (Exh. AG-7); Timothy Newhard on cost of capital and capital structure (Exh. AG-8). DOER presented one witness: Dr. Alvaro E. Pereira on performance based regulation (Exh. DOER-1). USWA presented two lay witnesses: Jodie Ajar and Helen Vonmaluski (Exh. USWA-1 and Exh. USWA-1, respectively). UWUA presented four additional witnesses: Nancy Brockway on rate, service quality and operations issues (Exh. UWUA-4); and Bay State employees Timothy Leary, Kevin Friary and Brian McCarthy on management and service quality issues (Exh. UWUA-5). KeySpan presented the testimony of Joseph F. Bodanza on the issue of the recovery of bad debt in the cost of gas adjustment clause (Exh. KED-1). MOC, MassPower and MASSCAP did not present any affirmative case.

Bay State responded with panel testimony to each of the witnesses provided by the Attorney General, and UWUA's witness, Ms. Brockway.

The Department held twenty-five (25) days of evidentiary hearings between July 5, 2005 and August 11, 2005 at its offices in Boston, Massachusetts. During the course of discovery and hearings, the Company responded to over one thousand nine hundred (1,900) information and record requests.[2] On August 31, 2005, the Attorney General, DOER, UWUA, USWA and KeySpan submitted initial briefs.

In the Attorney General's initial brief, it appears that he has recommended an approximately \$36 million reduction in rates from Bay State's proposed increase of \$22 million, which would result in a reduction from Bay State's current rates of \$14 million and a substantial and permanent reduction in Bay State's rate base. Such a recommendation is irresponsible and not supported by the evidence.

III. BACKGROUND

A. Bay State and the NiSource Companies

Bay State is a Massachusetts corporation and gas company under G.L. c. 164, sec. 1, formed from the aggregation of a number of smaller natural gas distribution and manufactured

[2] With regard to discovery, UWUA complains on brief that the case was mismanaged because some percentage of discovery was not timely filed. As discussed in the rate case expense portion of this brief, the parties and Department propounded an unanticipated volume of information and record requests on the Company to which the Company diligently and steadily responded, generally without objection based on materiality or relevance to the inquiry or the burden created. While UWUA claims it did not have all "discovery in hand" when hearings commenced, Bay State had responded to over 80% of all requests issued by that date on the first day of hearings. Many of UWUA's discovery questions were matters of public record which the UWUA could have obtained on its own. UWUA-1-8; UWUA-1-11; UWUA-1-12; UWUA-1-25; UWUA-1-26; UWUA-1-28; UWUA-2-9; UWUA-2-30. Exhs. Bay State therefore strongly disputes UWUA's claim of prejudice and "management incompetence."

gas systems throughout Massachusetts. Exh. DTE 2-3; Exh. BSG/DGC-1, p. 5. Bay State serves approximately 285,000 customers in its Brockton, Springfield and Lawrence divisions. Exh. BSG/SHB-1, p. 15.

Bay State merged with Northern Indiana Public Service Company ("NIPSCo"), a Northern Indiana combined gas and electric utility, creating NiSource Inc. ("NiSource"), in 1998. See Bay State Gas Company, Northern Indiana Public Service Company, NIPSCo Acquisition Company, D.T.E. 98-31 (1998). NiSource is a registered public utility holding company and a Delaware corporation. In 2000, NiSource merged with the Columbia Energy Group ("Columbia"), a natural gas pipeline and distribution holding company based in Herndon, Virginia (at the time, Columbia's energy distribution group was based in Columbus, Ohio). Other NiSource companies include the Columbia natural gas distribution companies of Ohio, Virginia, Pennsylvania, Kentucky and Maryland. All of the NiSource companies are provided management and administrative support services by NiSource Corporate Services Company ("NCSC"), which provides its services at cost pursuant to allocation methodologies approved by the United States Securities and Exchange Commission ("SEC").

1. Response to Intervenors Regarding Merger Issues

UWUA complains that Bay State was not "candid" with the Department and "misled the Department as to material facts" with regard to its merger with NIPSCo. UWUA Br., at 11. Bay State disagrees. The Department's order found that customers would benefit immediately from the merger because of a price freeze agreed to by the Companies that froze rates for five years. Bay State Gas Company, D.T.E. 98-31, at 45-46. The Department order permitted Bay State to seek recovery of the acquisition premium for the merger; Bay State has not. Bay State Gas Company, D.T.E. 98-31, at 47; See generally Exh. BSG/SHB-1 at 9-10. Therefore, customers have experienced no increase in base rates as a result of the merger. The Department's order required Bay State to meet service quality performance under the Department's service quality standards established in D.T.E. 99-84 and Bay State has consistently met the benchmarks and in several instances exceeded these benchmarks, required by the Department. Bay State Gas Company, D.T.E. 03-10; Bay State Gas Company, D.T.E. 04-12; Bay State Gas Company, D.T.E. 05-12; Exh. BSG/SHB-1, pp. 28-30. Bay State Gas Company, D.T.E. 98-31, at 48.

UWUA complains that Bay State must have intentionally misrepresented the record in the merger proceeding for the Department to find that its merger with NIPSCo would "significantly affect [the] workforce." UWUA Br., at 12.[3] However, Exhibit UWUA-1-1(B) demonstrates that in the year proceeding, and the two years following, the merger, the normal ebb and flow of employees occurred. However, as a result of the NiSource merger with Columbia in 2000, significant employee changes did occur, and as explained in the record at length, most of those changes occurred because of the creation of the corporate services company, NCSC, and the consolidation of many managerial, accounting, tax and financial functions in Columbus, Ohio. Exh. BSG/SHB-1 at 22, 23; Tr., at 1998-99. The record also demonstrates that all union staffing changes have been in compliance with Bay State's contracts with each of its unions. Exh. BSG/SHB-2. Accordingly, UWUA's concerns in this regard are without basis.

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[3] Bay State will address UWUA's assertions that sales were purposely reduced, infra.

B. Shared Services and Allocation of Costs

1. NiSource Inc.

NiSource is a registered public utility holding company under the Public Utility Holding Company Act of 1935 (15 U.S.C. § 79 et seq.) ("35 Act" or "PUHCA") and is regulated by the SEC.[4] NiSource owns all the common stock of the distribution, or operating, affiliates (including Bay State), the pipeline affiliates and the non-utility affiliates. The Department has recognized that the '35 Act imposes significant regulatory requirements. Blackstone Gas Company, D.P.U. 94-177, at 5-6 (1995). Under the '35 Act, it is unlawful for a NiSource subsidiary to perform any service for any other company within the NiSource system except in accordance with the terms approved by the SEC, or as required by SEC rule, regulation or order. '35 Act, at § 13(b); 15 U.S.C. § 79m(b). The SEC has historically regulated public utility holding companies in the public interest and for the protection of investors and consumers. Id. Inter-affiliate contracts have had to be performed economically, efficiently and for the benefit of the affiliates for whom such service is rendered. Id.; 17 C.F.R.§ 250.90(a) (2005); 17 C.F.R. § 250.91(a) (2005); Exh. BSG/SHB-1, pp. 18-21; Exh. DTE-5-3.

During the test year, NiSource's distribution affiliates receive economically priced services from NCSC. Exh. BSG/SHB-1, pp. 18-21; Exh. DTE-5-1.[5] As the study provided by

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[4] PUHCA has been repealed effective February 2006. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594. Nevertheless, the consumer protections established by PUHCA were in place during the test year and are embedded in NiSource's holding company structure and are currently expected to continue unchanged.

[5] Bay State commissioned a study of the reasonableness of NCSC test year expense because the Department has routinely requested detailed information relative to the reasonableness of service company charges as part of base rate investigations in the past. See Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 31 (1998).

Bayrenbruch and Company demonstrates, NCSC helps Bay State achieve efficiencies through shared, centralized services. Id.

a. Intervenor Concerns over Outsourcing of NCSC Functions

In late June 2005, NiSource entered into an agreement with IBM to provide certain business services currently provided by NCSC and the operating companies, including information technology, human resources, supply management, revenue recovery, accounting and call center management. Exh. DTE-18-1; RR-AG-9. The agreement will enable IBM to assist NiSource with some of the information technology, accounting and human resources management operations that are not central to its core business of providing electric and gas service. Exh. DTE-18-1. The intent of this agreement is to free-up NiSource resources for investment in distribution and pipeline safety and reliability, as well as increased gas capacity and storage. Exh. DTE-18-1.

i. Response to Attorney General

The Attorney General states that the IBM contract "provides a known and measurable reduction to Bay State's test year cost of service." AG Br., at 91. In support, he cites a forward-looking SEC Form 8-K disclosure issued by NiSource that estimates a savings of over $530 million over the contract term of 10 years. Exh. DTE-18-1(a). The Attorney General then recommends a single pro forma adjustment to reflect "expected" future savings for Bay State on an annualized basis of $3.43 million. AG Br., at 93.

The Attorney General's proposed adjustment to Bay State's pro forma test year cost of service is speculative, inaccurate, and contrary to Department precedent. The contract was signed less than 90 days ago. Exh. DTE-18-1(a), p. 4. Estimated savings that may occur over a 10-year period reflected in the forward-looking SEC disclosure statement do not rise to the level of "known and measurable" reductions to the test year revenue requirements.[6] The benefits of the contract will only be known if and when savings occur and NiSource capital and other resources can be focused on infrastructure development for the operating companies. The current estimates of the benefits of the contract are far too speculative to use to adjust Bay State's test year expenses. Moreover, given the long term nature of this transaction and the necessary up front costs, it is virtually certain that no savings at all will accrue to NiSource or Bay State in the rate year. Exh. DTE-18-1; Exh. AG-24-2.

In previous cases, the Department has required that, to be allowed, a pro forma adjustment must be certain to occur in the rate year. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 76 (2002). Since the Attorney General's proposal does not reflect an adjustment to Bay State's test year revenue requirement that is known or measurable, it must be rejected under Department precedent. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 76. The Attorney General has provided no justification for deviation from this long-standing regulatory precedent. Since the Attorney General's proposal does not reflect an adjustment to Bay State's test year revenue requirement that is known or measurable, it must be

[6] The Attorney General's recommendation is also invalid because it fails to include the "estimated" costs to achieve, or transaction costs of the IBM contract, which must occur before any savings can be realized. Over the next two or three years, NiSource costs will be $91 million before any savings may be achieved and another $50 million in governance over the next 10 years. Exh. DTE-18-1

rejected under Department precedent. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 76; Boston Gas Company, D.T.E. 03-40, at 11 (2003).

ii. Response to UWUA

UWUA complains that Bay State has failed to be "candid" with the Department about its plans to outsource certain NCSC and Bay State functions, even though Bay State provided extensive documentation and sworn testimony regarding NCSC's forward-looking plans and proposals both in discovery and during the hearings. UWUA Br., at 14; compare Exhs. USWA -1 through USWA 1-8. Exh. AG 24-2; Exh. DTE 18-1; and RR-AG-9. In fact, the outsourcing initiative was initially discussed in Mr. Bryant's prefiled testimony. Exh. BSG/SHB-1 at 28; Tr. Vol. 1; Vol. 6; Vol. 20; Vol. 15; Vol. 10, Vol. 16; Vol. 8.

Also, Bay State has agreed that no staffing changes would take place during this proceeding as a direct response to a motion filed by UWUA. See Local 273 Motion to Preserve Status Quo; See Local 273 Notice of Withdrawal of Motion to Preserve Status Quo (Aug. 10, 2005). There is absolutely no evidence in this record, or elsewhere, that "NiSource's goal is to outsource as many jobs as possible." Cf. UWUA Br., at 16. Such hyperbole is inappropriate and has no place in this proceeding.

As Mr. Bryant indicted, Bay State and NiSource are always seeking opportunities, consistent with Bay State's obligation as a public service company, to concentrate on its core functions of ensuring safe, reliable and cost-efficient service. The Company is also under continuing obligation imposed by the Department to explore all cost savings measures and potential opportunities to achieve efficiencies of all kinds. Guidelines and Standards for

Acquisitions and Mergers, D.P.U. 93-167-A, at 5 (1994). NCSC, itself, serves to "outsource" functions previously performed by Bay State, Columbia and NIPSCo. employees. Those functions are now performed by NCSC employees, either in Massachusetts or elsewhere. Exh. BSG/SHB-1, AG-3-8, Tr., at 1939. Other similar outsourcing initiatives by NCSC have been routinely undertaken. Exh. AG-3-8. Moreover, the record demonstrates that Bay State's participation in NiSource's outsourcing initiative with IBM does not mean jobs are necessarily lost: many employees are being rebadged throughout the organization and will remain at work with IBM, or as an IBM subcontractor. Exh. DTE-18-1; Exh. AG-3-8, Tr., at 191, Tr., at 2672-74.

Finally, the record is replete with evidence that NiSource and Bay State have undertaken this outsourcing initiative after engaging in a diligent investigation into the positive and negative aspects of an agreement with IBM. Tr., at 3311. No important undertaking such as this is without risks. However, Bay State, as does NiSource, believes that this initiative will assist in ensuring that safety, reliability and service to customers across its various service areas are maintained and improved, by freeing up capital resources to invest in its natural gas distribution and pipeline operations.

iii. Response to USWA

The USWA appears to be concerned that the contract with IBM will remove from Bay State control of business functions that secure service quality for Bay State's customers. See generally, USWA Br.[7] USWA urges the Department to set service quality standards and staffing benchmarks that ensure the "recent gains made by the Company in the test year, with regard to consistently meeting service quality indicators are not lost during the rate year or any time thereafter." USWA Br., at 2.

As discussed below, Bay State's telephone service quality performance did suffer because of staffing reasons (e.g., attrition, transfers and a hiring freeze), as well as significant changes to its customer information system. Tr., at 64-65; See generally Tr., Vol. 10; Tr., Vol. 20. However, those problems have been remedied, and were remedied before the test year in this proceeding, in part due to application of the Department's service quality standards, and associated penalties. Tr., at 1649; Tr., at 64-65. The record also indicates that staffing cuts were initiated in order to determine the level of staffing required to maintain service quality at the most efficient and economic levels while introducing certain new technologies designed to serve customers. Exh. BSG/SHB-1; Tr., at 1667. However, when service quality deteriorated and penalties were assessed, Bay State took action to correct the problem. This process will not change under the contract with IBM. Tr., at 208; 1706; 3311. The contract with IBM does not relieve Bay State of any of the obligations established by the Department to maintain customer service standards now or at any time in the future. Tr., at 208-14; 254-56; 3311. The contract is intended to produce a higher level of customer service at lower costs. Therefore, the USWA's concerns are misplaced.

[7] The USWA appears to have inadvertently omitted pagination of its brief (confidential). Page references for the purpose of response have been manually derived by Bay State.

2. Bay State's Allocation of Shared Costs to Northern Utilities

Bay State incurs shared costs with its affiliate, Northern Utilities, Inc. ("Northern"). In order to ensure that costs incurred by Bay State are allocated or charged, where appropriate, to Northern, Bay State and Northern have a management services agreement that defines the parameters of cost allocation. Exh. BSG/SHB-4; Exh. AG-1-26; Exh. AG-19-7. Where possible, all costs are directly charged.

3. Management of Bay State

Bay State's initial filing demonstrates that Bay State is actively concerned about, and responsive to, issues of customer service. Exh. BSG/SHB-1, p. 26-35. It closely manages customer information, customer satisfaction, and customer service. It manages its regulatory relationships and it proactively addresses operational issues. Id. It has been financially stable. It has also managed expenses without a base rate increase and without updating its rate base, for over 13 years. Exh. BSG/SHB-1, p. 8. It has managed significant organizational changes through two mergers to become a stronger, more fiscally sound company. See, Exh. BSG/SHB-1, pp. 22-23.

a. Response to UWUA

UWUA alleges that management performance by Bay State has been "subpar" for "outsourcing safety functions;" "plunging itself into debt;" "failing to provide adequate staffing and investment;" "compromising call center performance [and] system expansion;" failing to meet its public service obligations to low-income customers;"[8] and "plunging into a massive outsourcing project, at a time when industry is assessing the pros and cons of such deals."[9] UWUA Br., at 19. UWUA seeks a management audit of Bay State. UWUA Br., at 59. Each of these claims is without merit, and no "management audit" is warranted at this time.

First, there is no evidence that Bay State was imprudent and disregarded its obligation to provide safe service in outsourcing its Massachusetts locating functions in 1998. UWUA Br., at 33-35. In fact, Bay State's affiliate, Northern, also outsourced its New Hampshire locating function at the same time and that function is still outsourced today. Tr. at 268; Tr. at 466 (Lawrence Division). The 1998 Attleboro incident was a tragic, unanticipated confluence of events (involving Bay State, the locating company, and Attleboro Water Department personnel) that occurred nearly 8 years ago. It is irrelevant to Bay State's current operations, service or management. Moreover, Bay State took all appropriate actions after the event. RR-UWUA-3; Exh.-AG-1-79; RR-DTE-84; Exh. UWUA-1-11. The Attleboro incident was not the result of "outsourcing," or "cost-cutting goals," or of any single management decision made by Mr. Cote,[10] or Bay State.

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[8] This UWUA assertion is completely unsupported by the record. See also, Exh. UWUA 39-41. Bay State has actively participated in D.T.E. 01-106-A, to increase penetration of low-income rates, and was one of the first utilities to put solid rate proposals before the parties and the Department to assure maximum participation. Bay State also informs its customers about the availability of energy assistance and participates in many state-wide and local assistance programs. Exh .BSG/SHB-1, p. 32-36. Bay State also ensures that there are many outlets for making payments in lieu of Bay State sponsored walk-in centers, including supermarkets and convenience stores. Cf. UWUA Br., at 28-30.

[9] This UWUA assertion was examined with UWUA's other "outsourcing" complaints.

[10] UWUA's undocumented hearsay testimony, attributed to Mr. Cote, that outsourced errors and resulting third party damage were a "cost of doing business," is completely unfounded. UWUA Br., at 34. Mr. Cote is, and has been, Chairman of New England Dig Safe since the late 1980's and was a primary proponent of the legislation that now protects the public from third party damage in each of the five New England states. Exh. AG-2-61.

(Footnote continued on next page)

Second, the merger between NiSource and Columbia, while accompanied by the acquisition of debt, also brought personnel synergies, financial diversity, and a sophisticated national presence in the natural gas pipeline, distribution and storage industry. Tr., at 1634-36; Tr., at 3305. These factors will provide long term benefits to customers.

Third, Bay State has acknowledged that reductions in staffing resulted in service issues in 2001 that were remedied in 2002, 2003 and 2004. Tr., at 64-6; See generally, Tr. Vol. 10, Tr. Vol. 20 Current management has been proactive in addressing service quality concerns and has ensured that staffing matches service requirements. Tr. 20; See also Exh. UWUA-1-2D at 1-2, 12; Exh. UWUA-1-24(D), p. 1-3.[11] In addition, Bay State has invested substantially in 2003 and 2004 in certain call center technologies intended to serve customers better. See e.g., Exh. BSG/DGC-10; Exh. BSG/DGC-11.

A management audit of Bay State suggested by UWUA is completely unnecessary and would be a diversion of the Department's limited resources and a duplication of the resources expended in this investigation. Much of the testimony of this proceeding was devoted to analyzing management activities related to customer service. Tr. Vol. 1, Tr. Vol 2, Tr. Vol. 3, Tr. Vol. 6, Tr.Vol. 8, Tr. Vol. 10, Tr. Vol. 12, Tr. Vol. 15, Tr. Vol. 20. The record demonstrates

(Footnote continued from previous page)
Mr. Cote has spent an extensive portion of his professional career promoting Dig Safe as a means of protecting the public from natural gas leaks. Id. The attributed statement was either misheard, has been forgotten in part, or, more likely, taken out of context because it was made so long ago.

[11] UWUA asserts Mr. Bryant and Mr. Cote have no "control" over staffing decisions, regardless of need. UWUA Br., at 37. The statement is misleading. While Mr. Bryant and Mr. Cote do not make unilateral business decisions without informing senior management, they do have authority for staffing in Massachusetts. Tr., at 3162.

that management is supervising customer service operations closely with a knowledgeable and committed staff of professionals.

C. Rate Case History

Bay State last requested a base rate increase in 1992. Bay State Gas Company, D.P.U. 92-111 (1992). During the 13 years since its last base rate request, Bay State is the only gas utility in the Commonwealth not to seek one or more full base rate increases. In 1997, pursuant to a pre-filing settlement with the Attorney General, Bay State was permitted two annual base rate step adjustments to recover costs associated with non-revenue producing infrastructure replacement. Bay State Gas Company, D.P.U. 97-97 (1997).

In Bay State's last base rate case, Bay State filed for an increase of $20,646,572, or 7% of distribution revenues, and was granted an increase of $11,523,418, or 3.9%. Bay State Gas Company, D.P.U. 92-111 (1992). Since the test year for its last base rate proceeding (when Bay State's rate base was last updated), Bay State's net investment in its natural gas distribution infrastructure and other rate base items increased by 45%, from $273,512,000 to $397,106,628. Exh. BSG/JES-1, p. 5; Exh. BSG/JES-1, at Sch. JES-2. Significantly, the growth in Bay State's rate base was led by mandatory mains replacements, upgrades and other non-revenue producing investments designed to ensure the safety, reliability and operational integrity of Bay State's gas distribution system. Bay State has also experienced increased costs for wages and benefits, insurance, property tax and bad debt expense, all while experiencing a period of declining load growth and relatively flat sales. The increase in Bay State's costs also reflects new investments and expenses required to support gas restructuring and competition, Year 2000 and other necessary technological upgrades, all impacting Bay State's customer information systems, supplier interfaces, gas management abilities, and increased regulatory activities.

IV. BAY STATE'S RECORD ON SERVICE QUALITY

Bay State met or exceeded the Department's Service quality ("SQ") standards 2004, 2003, and 2002. Exh. BSG/SHB-1, pp. 30-31. In 2001, Bay State failed to achieve a customer satisfaction target, that the Department has since eliminated. In 2000, Bay State missed a number of service quality standards, and, as a result, paid a substantial penalty.

The intervenor comments assert that the Department should tighten the SQ standards as they are applied only to Bay State; that in addition to the SQ penalties that apply to Bay State, the Department should further punish Bay State by reducing Bay State's going-forward allowed return on equity as a result of the limited failure in 2000-1 to meet all SQ standards; and that the Department rule on whether G.L. c. 164, secs. 1E and 1F require Bay State to cease making staffing changes (of any kind (union or non-union) even though it has met the Department's SQ standards during the previous three years.

A. Response to Intervenors

1. <u>Response to Attorney General and USWA</u>

The Attorney General and the USWA argue that the Department should adopt staffing benchmarks as a result of this proceeding. AG Br., pp. 121-123; USWA Br., pp. 9-13. Since this argument is made also made by UWUA's relatively more comprehensive analysis, to avoid repetition, Bay State's response to the UWUA's proposals apply to the Attorney General's and USWA's request for staffing benchmarks as set forth below.

2. **Response to UWUA**

UWUA argues that NiSource focuses on "strategic corporate goals" that "bleed its Massachusetts operating company" at the expense of its customers. UWUA Br., p. 6. UWUA challenges Bay State's recent improved service quality measures as a "transparent attempt by the Company to pump up test year figures to obtain more favorable rate relief." UWUA Br., p. 6. UWUA proposes that the Department set the allowed return for common equity at the "lowest end of the range of reasonableness for such returns." Id. Bay State objects to UWUA's unwarranted characterizations and its proposed return in equity.

Bay State has met and exceeded its service quality measures in the three years preceding this investigation. The record further indicates improved Company strength of management, greater local control over Bay State operations and an improved record of customer satisfaction. Exh. BSG/SHB-1 at 28-30; Tr. 20 at 3304.

Bay State has never denied that there were challenges following its acquisition by NIPSCo and the merger of NiSource and the Columbia Energy Group. However, those challenges are now past history and more recent history demonstrates Bay State's and NiSource's consistent and steady management direction toward a stronger, financially stable, and highly reliable and efficient natural gas distribution system.

UWUA suggests that the Department was lax in its investigation of Bay State during 2001 and 2002, especially in comparison to the oversight provided by the Maine and New Hampshire Public Utility Commission.

The Department, conducted a generic investigation from 1999 through 2003 to determine the appropriate level of service quality for all utilities. Investigation into Service Quality, D.T.E. 99-84. The result of this multi-year investigation, that is renewed now as D.T.E. 04-116, was a balanced approach providing incentives and penalties in the event a utility fails to meet the service quality expectations. The Department has not been lax in its oversight of the standards as is implied by the intervenors. The Department's investigation in D.T.E. 99-84 and implementation of the rules established in that proceeding has been balanced and thorough.

UWUA's proposed recommendations (UWUA Br., at 32) regarding changing the telephone service factor to a monthly reporting and compliance requirement and to increasing the benchmark for calls answered are inappropriate and interfere with the symmetry of the statewide reporting requirements imposed on every utility in the Commonwealth.[12] Moreover, it would be inappropriate for the Department to impose this type of requirement on Bay State when service quality standards are currently under review by the Department in another investigation. UWUA should propose any changes to service quality standards it believes are warranted, as part of the Department's investigation in D.T.E. 04-116.

[12] UWUA raises the issue of Bay State's trunk line maintenance. Mr. Bryant testified that if a reduction in trunklines occurred, it occurred in 1998 or 1999, before the NiSource merger with Columbia, and therefore was not a response to "cost cutting" or reductions of staff as a result of the merger. UWUA Br., at 23. In fact, current Bay State management was proactive in correcting the trunkline issue. Bay State should not be penalized further beyond the sanctions already assessed under the SQ standards.

Finally, with regard to UWUA's assertion that the Department has failed to enforce a statutory requirement that staffing levels be established, Bay State does not agree that the Department has such a duty, nor would it be appropriate to do so in this case. This investigation of Bay State rates is not the appropriate forum in which the Department should make findings of statewide impact, such as statutory interpretations regarding G.L. c. 164, Secs. 1E and 1F, with regard to staffing benchmarks or any other service quality area, especially when an investigation that includes all the Commonwealth's utilities, D.T.E. 04-116, is pending. All utilities should have the opportunity to comment on such an issue of statewide impact. It would be equally inappropriate for the Department to "extend [a] moratorium" on staffing changes that arose out of Bay State's voluntary action as is suggested by UWUA.[13]

Under the Department's service quality standards, utilities must meet those standards or be subject to penalties. It is not the role of the Department to micro manage a utility's staffing levels needed to meet those standards, and the UWUA's requests that the Department do so should be denied.

V. STEEL INFRASTRUCTURE REPLACEMENT PROGRAM

Many of the resources of the Attorney General and the Department were devoted to the necessity for the steel infrastructure replacement ("SIR") program that Bay State introduced as part of its initial filing. Exh. BSG/DGC-1, pp. 15-18; Exh. DTE-8-32. Bay State's SIR program

[13] Lastly, UWUA's statement that no company in the Commonwealth has reduced staff as much as Bay State since the Restructuring Act was passed (UWUA Br., at 43, 59) is unsupported either on brief or by the record in this proceeding. The UWUA's statement that staffing cuts have affected current service quality (UWUA Br., at 59) is also without support on the record.

is significant in a number of ways. First, it is a proactive step to address a problem that threatens public safety and the integrity and reliability of its infrastructure built and maintained to serve the public. Second, Bay State's solid record of maintenance and inspection and its careful multi-year analysis of leak rates demonstrate that the leaks on bare and non-cathodically protected steel main and services pipe are increasing at an accelerating rate. Non-discretionary capital investment in excess of the amounts normally invested in pipe replacement are now necessary to maintain Bay State's system. Third, the rate mechanism (the Annual Base Rate Adjustment Mechanism, or "ABRAM") that Bay State proposes to stem the earnings erosion that will occur during the SIR is designed to ensure that SIR expenditures by Bay State can be reviewed relatively easily by the Department.

A. Necessity for SIR Program

1. <u>Background</u>[14]

Bay State's first priority is ensuring that it delivers natural gas to its customers through a safe and reliable distribution system. Exh. BSG/SHB-1, p. 36. Bay State's distribution system consists of a large amount of unprotected steel mains and services that are subject to corrosion. Exh. BSG/DGC-1, p. 15. Bay State determined that there is an increasing number of leaks in areas where bare and unprotected coated steel piping is concentrated. Exh. BSG/DGC-1, p. 15. The timely replacement of Bay State's remaining bare and unprotected coated steel will require a substantial accelerated financial and operational commitment by Bay State. Exh. BSG/DGC-1,

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[14] For a detailed description of the physical and operational characteristics of Bay State's distribution system in Massachusetts, see, Exh. BSG/DGC-1, pp. 10-15.

p. 16; Exh. BSG/SHB-1 p. 39; Tr. , at 2448, 287-90 and 329. Bay State has continuously replaced[15] and retired bare and unprotected coated steel in its system since the late 1960's and early 1970's through the present. Exh. BSG/DGC-1 p. 17; Exh. AG-23-10. The Company currently replaces pipe segments following an analysis of historical leak rates, along with a number of other risk criteria. Exh. BSG/DGC-1, p. 17; Exh. AG-2-61; Exh. AG-14-28; Exh. DTE-16-10; Exh. AG-6-1.

2. <u>Accelerating Leak Rates</u>

Bay State has approximately 583 miles of unprotected steel remaining in its system. Exh. BSG/DGC-1, p. 16. Exh. DTE-3-6 Exh. AG-14-25. In spite of a solid history of replacing bare and unprotected coated steel mains, Bay State has averaged over 700 corrosion leaks per year in its system over the past 5 years. Exh. BSG/DGC-1, p. 16; Exh. AG-2-16. This is 3 times the leak rate present 17 years ago despite a significantly reduced inventory of bare and unprotected coated steel, and is a clear indication that damage and deterioration associated with corrosion is not only becoming more severe, but is accelerating. Exh. BSG/DGC-1, p. 16; Exh. DTE-3-6; Exh. AG-2-16. The remaining 106 miles of unprotected coated steel pipe is not suitable for cathodic protection. Exh. AG-2-50; Exh. AG-2-53; Exh. AG-25-1. Bay State has 2,034 miles of cathodically protected steel as of December 31, 2004. Exh. AG-2-51.

[15] For a complete discussion in the record of the technology of cathodic protection that was imposed on and replaced the bare steel and the qualifying sections of unprotected coated steel, and to understand the nature and limitations of plastic distribution pipe, see, e.g. Exh. BSG/DGC-1, p. 10-15; Tr., at 3452-53; Tr., at. 3654, 3675; Tr., at 3950, 3954. For a discussion in the record of the imperatives of the Federal Pipeline Safety Act of 1971, which mandate the replacement of, and, where replacement was not possible, the consistent monitoring of systems for corrosion, see e.g., Exh. DTE-3-2; Exh. AG-2-12, 2-14

Bay State's Brockton division has experienced nearly a 50% increase in corrosion leaks from 1993 to 2003 (404 to 601), even though Bay State retired or replaced 31% (175 miles) of unprotected steel mains during that same period. Exh. BSG/DGC-1, pp. 16-17; Exh. AG-2-16; RR-DTE-10; Exh. AG-2-33. The number of leaks per mile for bare and unprotected coated steel in Brockton exceeds the average number of leaks per mile for the bare and unprotected coated steel for other regional LDCs, even though Bay State has a better than average leak backlog/repair ratio. Exh. BSG/DGC-1, p. 17; Exh. AG-2-16.

Even with Bay State's continuing replacement of the bare and unprotected coated steel segments that present the most risk each year, the rate of corrosion leaks for unprotected mains has continued to increase. Exh. BSG/DGC-1, p. 17; Exh. AG-2-33; Exh. DTE-3-6; Exh. AG-4-19. Bay State removed almost 700 miles of bare and unprotected coated steel mains from its system in the last 19 years (1,291 miles in 1985 reduced to 583 miles in 2004), yet the number of corrosion leaks climbed from 339 in 1985 to 674 in 2004. Exh. BSG/DGC-1, p. 17-18; See DTE-3-11; Exhs. AG-25-3; AG-14-25; Exh. DTE 3-6; Exh. AG-6-8.

Bay State's management has determined that continual system degradation due to unrelenting corrosion will undermine Bay State's ability to meet peak day needs and operate the system safely. Exh. BSG/DGC-1, p. 7-18; Exh. BSG/DGC-1, p. 20; Exh. AG-2-33. The SIR is the appropriate response to the leak rates in its gas distribution system.

No party contests the necessity of removing the remaining bare and unprotected coated steel from Bay State's distribution system. The key issues are how the SIR replacement should take place and how (and if) Bay State should recover the costs associated with the program.

B. Description of SIR Program

At Bay State's historic replacement rate (i.e., the average replacement rate over the last five years), Bay State estimates it would take approximately 30 to 40 years of replacement activity to replace the remaining bare and unprotected coated steel. Exh. BSG/DGC-1, p 17. The record demonstrates that the acceleration of the corrosion rate of bare and unprotected coated steel is threatening to outstrip Bay State's ability to cost-effectively address the rate of leakage. Exh. BSG/DGC-1, p. 17. After carefully analyzing the circumstances, relevant population density, municipal requirements and the necessity for replacement, Bay State determined it would be most cost-effective to undertake an area-based replacement strategy that will permit the Company to bid the work to contractors competitively, and a contractor to price its bids based on an efficient program implemented by geographic region. Exh. BSG/DGC-1, p. 18; Tr., at 2441; RR-AG-101; RR-AG-87.

An area or geographic replacement targets discrete areas, neighborhood-by-neighborhood, block-by-block, in a geographically continuous fashion. Exh. BSG/DGC-1, p. 18-19; Exh. DTE- 3-29; Exh, DTE 3-28.; Bay State believes that this is the most efficient method of replacement. Exh. BSG/DGC-1, p. 18-19; Exh. DTE-3-28; Exh. AG-2-59; RR-AG-101.

The SIR program will be efficient because construction crews will be able to stage work continuously by shifting the worksite along the pipe being replaced, day by day, rather than opening and closing worksites and relocating labor and equipment across towns or across the service territory. Exh. BSG/DGC-1, p. 19; Exh. DTE-3-28. In addition, as Mr. Cote testified, the SIR will result in a per foot installation cost less than would be achieved by bidding smaller and more discrete tasks on a per project basis. Exh. BSG/DGC-1, p. 19; RR-AG-101. The public will benefit because the program minimizes disruptions in traffic flow by concentrating work in one section of a municipality. Exh. BSG/DGC-1, p. 19.

The SIR program is established within a defined period of 10 to 15 years, in order to produce the maximum efficiencies from the project, reduce construction costs, minimize public inconvenience and ensure public safety. Exh. BSG/DGC-1, p. 23; Exh. AG-2-59; Exh. DTE-3-31. The SIR program will replace all bare and unprotected coated steel mains and other related facilities based on the needs of the distribution system, in accordance with the basic tenets of system engineering and planning. Exh. BSG/DGC-1, pp. 23-24. Replacements will be determined by the condition and age of the pipe, geographical proximity, the capacity needs of the area, and expected growth in system demand requirements. Exh. BSG/DGC-1, pp. 23-24; Exh. AG-2-59. Efficiencies will be maximized and costs minimized by addressing large segments of the system for replacement on a planned, systematic basis, and by concentrating contractor resources and leveraging competitive bidding processes in order to drive down costs of time and materials. Exh. BSG/DGC-1, p. 24; see e.g., Exh. DTE-3-34 (Supp.); Exh. AG-23-6.

By identifying Brockton as the largest segment of the system that requires attention (through leak rates and repair percentages), Bay State will focus resources and complete full segment replacements and tie-ins in an orderly and predictable fashion in that area first.[16]

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[16] In 2005 the complete list of municipalities scheduled for facilities replacement includes: Attleboro, Duxbury, Franklin, Medway, Brockton, Scituate, Foxboro, Randolph, Stoughton, Hanson, Norton, Taunton,
(Footnote continued on next page)

Replacing pipe involves cutting of the street surface (if the main underlies a street), excavating a trench a foot or so wider than the pipe to be installed, installing the size and type of new pipe consistent with engineering and operations system design requirements, pressure testing it, proceeding to tie-in the existing or new services and mains into the new line, and finally, once the new line is tied in to all the customers, the old line is abandoned, purged of remaining natural gas, and capped by welding or cementing. Exh. BSG/DGC-1, pp. 24-25; Exh. DTE-3-3; Exh. AG-2-1. The replacement mains and services are expected to be plastic or cathodically protected steel throughout most of the system. Exh. BSG/DGC-1, p. 25; Exh. DTE 3-3.

It is also important to note that gas distribution systems are generally planned and designed on a 50-year horizon. Bay State's planning dictates that Bay State anticipate engineering and operations requirements as far into the future as possible. The choice and size of replacement pipe will take into account these engineering and other requirements of system design. Exh. BSG/DGC-1, p. 25; RR-DTE-153; Exh. UWUA 3-48. The evidence is clear that this is NOT a program for system expansion, but rather a program to maintain system integrity and reliability and to promote public safety. RR-DTE-153; Exh. DTE-3-15.

Corrosion leakage exists in all of Bay State's system, but it is particularly severe in the Brockton distribution system, which has the most bare and unprotected coated steel pipe per mile. Exh. BSG/DGC-1, p. 19; Exh. AG-2-1; Exh. DTE-3-9; RR-DTE-10. Moreover, as Mr. Cote described, the Brockton Division requires operating pressure of 100 pounds per square

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Marshfield, Medfield, Norwell, Walpole, Pembroke, West Bridgewater, East Bridgewater, Hanover, Sharon, Holbrook, Seekonk, Wrentham, Easton, Canton, Northampton, Chicopee, South Hadley, Lawrence, Methuen, and Andover.

inch ("psi") to meet its delivery requirements. Exh. DTE-3-8. The higher operating pressure causes corrosion leaks somewhat more quickly than an unprotected steel system operating at a lower pressure, resulting in more leaks per mile on that system as compared to a lower pressure system of the same age. Exh. BSG/DGC-1, p. 19; Exh. DTE-18-23; Exh. AG-2-23.

C. Proposed SIR Cost Recovery Mechanism as Part of the ABRAM

The proposed Steel Infrastructure Replacement ("SIR") Base Rate Adjustment mechanism is intended to compensate Bay State for the extraordinary accelerated capital outlay required to more aggressively manage the increasing leak problems, and will reduce the regulatory expense of frequent base rate increase requests that would be required without the SIR adjustment. Exh. BSG/DGC-1, p. 15.

In the revenue recovery mechanism explained by Mr. Ferro, Bay State proposes to recover only the incremental SIR costs that are known and measurable and reasonable in amount. Exh. BSG/DGC-1, p.25; Exh. BSG/JAF-2, p. 23-33. The proposed SIR Base Rate Adjustment would apply to the incremental SIR plant additions, the pre-tax weighted average cost of capital approved as part of the Department's order in this case as well as applicable federal and state income tax rates. Exh. BSG/JAF-2, p. 23-33; Exh. BSG/SHB-1, p. 41; Exh. DTE 3-34. Carrying costs associated with each construction period would be recovered. Exh. BSG/SHB-1, p. 41; Exh. DTE 3-34. As described below, the adjustment also provides for an offset for the reduction in operations and maintenance expenses associated with the SIR program.

The reason for Bay State's request for a recovery mechanism is that the magnitude of the SIR program is substantial in cost and scope. Exh. BSG/SHB-1, p. 38; Exh. AG 3-37.

Undertaking a significant non-discretionary project, over and above historical investment levels captured in its base rates, will eliminate Bay State's ability to earn its allowed return even if it has a PBR in place that adjusts rates. Exh. BSG/SHB-1, p. 39. Mr. Bryant testified that Bay State's earnings are expected to be eroded on the first day of its rate year in light of the level of capital expenditures made for its 2005 SIR program, a significant level of spending in relation to its net plant as of the end of the test year. Exh. BSG/SHB-1, p. 40.

It is Bay State's view that filing repeated, traditional base rate proceedings to recover the cost associated with this level of infrastructure replacement is administratively inefficient and will drive up the costs ultimately borne by ratepayers. Exh. BSG/SHB-1, p. 38. Assuming Bay State were required to file rate cases every two years to recover these legitimately incurred expenses, and the program lasts 10 years, ratepayers may bear in excess of $5 million in rate case litigation costs (assuming a total cost of $1 million per case) and an unnecessary administrative burden would be placed on the Department and other parties. Exh. BSG/SHB-1, p. 83. Based on the current rate case expense in this proceeding, this amount could be significantly higher. Exh. DTE-15-58. The Company's proposal results in administrative efficiency, while allowing the Department the opportunity to carefully review all aspects of the Company's performance associated with the SIR program. Exh. BSG/SHB-1, p. 41; Exh. BSG/JAF-2, pp. 23-33.

Bay State proposes to make an annual filing with the Department to include the eligible expenses associated with the SIR program incurred during the previous calendar year. Exh. BSG/SHB-1. The annual filing will be submitted by June 1 of each year to allow sufficient time for the Department and other interested parties to review the proposed adjustment to its rates which would take effect on November 1 of each year, coincident with Bay State's cost of gas adjustment ("CGA") and ABRAM, which will also include the PBR annual adjustment. BSG/SHB-1, p. 41; Exh. DTE 3-34. The SIR Base Rate Adjustment would not be subject to future reconciliation following the Department's investigation and final order of SIR program costs each year. Exh. BSG/SHB-1, pp. 41-42.

Bay State recommends, as part of its annual SIR Base Rate Adjustment review process, that the Department be provided sufficient information to audit Bay State's program costs in a manner consistent with the Department's existing directives related to its review of other non-discretionary non-revenue producing rate base additions. Exh. BSG/DGC-1, p. 29; Tr., at 3322-23; Exh. BSG/SHB-1, p. 42. For this purpose, Bay State proposes a Capital Expense Tracking ("CET") procedure, created to identify and provide the necessary support for the SIR program in a formal audit process. Exh. BSG/DGC-1, p. 29; Exh. BSG/DGC-6 (Capital Expense Tracking). The CET allows the tracking of all costs for the SIR program. Id.

The CET provides a Documentation Responsibility Matrix that will ensure the appropriate pre and post construction evaluations are completed and the necessary documentation of these evaluations are prepared before being filed with the Department. Exh. Exh. BSG/DGC-1, p. 29; Exh. BSG/DGC-6 (Capital Expense Tracking) Each project segment under the SIR program will be accompanied by a CET SIR project file, created to provide the analyses for the project, from estimation to completion. Exh. BSG/DGC-1, p. 29; Exh. BSG/DGC-6.

As reflected in the SIR Base Rate Adjustment mechanism, the program accounts for future reductions in main-related corrosion leak repairs associated with expanded use of plastic or cathodically protected steel throughout the Bay State system. Exh. BSG/DGC-1, p. 25. As a result, the Company fully expects to systematically reduce the recent 4-year average level of main corrosion leak repair-related operations and maintenance expenses.[17] Id. Therefore, as explained by Mr. Skirtich (Exh. BSG/JES-1) and Mr. Ferro (Exh. BSG/JAF-2), the Company proposes a leak repair O&M offset to its SIR program expenditures.

Bay State's SIR recovery mechanism and proposed review process will allow Bay State to recover the cost of its incremental non-discretionary investment, including depreciation and property taxes; will allow for annual updates after the close of the construction season; and will allow the Department, the Attorney General and other parties to review, annually, Bay State's proposed SIR costs at a significantly lower cost than a full base rate case proceeding. BSG/SHB-1, pp. 41-43. It is reasonable, efficient and should be approved.

D. Response to Intervenor Concerns

1. Response to Attorney General

The Attorney General has three primary concerns regarding Bay State's SIR program. The Attorney General believes that Bay State failed to maintain an appropriate level of capital expenditures following the merger with NIPSCo and therefore Bay State is responsible for the

[17] The Company follows generally accepted accounting principles by capitalizing corrosion leak repairs to services, which constitute a full replacement of the given pipe, while booking main leak repairs, which are repairs to a given pipe, to O&M.

fact that now an accelerated program is necessary. AG Br., at 16. The Attorney General takes issue with Bay State's geographic or area-based approach. AG Br., at 22. Finally, the Attorney General asserts that Bay State undertook a flawed analysis of the cause of the leaks on the system, and therefore is unable to justify use of broad-based replacement, and he suggests that Bay State's prior replacement methods are sufficient. AG Br., at 26-28. Bay State strongly disagrees with each aspect of the Attorney General's analysis.[18]

a. Bay State Did Not Defer Maintenance on its System

With regard to the Attorney General's assertion that Bay State failed to maintain its distribution system in the years following the merger with NIPSCo and otherwise deferred needed maintenance, Bay State points out that the evidence does not support this conclusion. See also Exh. AG 25-7. Bay State has been fully compliant with the mains replacement mandates established under 49 CFR part 192 and the Department's cast iron replacement regulations under 220 CMR. Exh. BSG/LRK-2, p. 8; Exh. AG 6-10; Exh. USWA-2-20. The Department has regularly inspected Bay State's maintenance program for bare and unprotected steel mains on both a scheduled and surprise basis and has never expressed any concern that Bay State was not fulfilling its operational or regulatory obligations. See Exh. AG 2-7; Exh. AG 2-8. Bay State has been proactive in identifying the problems with its unprotected steel infrastructure and did not wait for regulatory or compliance action in order to address the issue. See, Exh. DTE 20-2; Exh. AG 8-4; Exh. UWUA 3-46.

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[18] The Attorney General claims that Bay State has the worst corrosion leakage rates in the Commonwealth. Bay State disagrees that any reasonable analysis of available data demonstrates this.

There is other evidence that Bay State did not defer maintenance expenses. Exh. AG 2-16; Exh. AG 6-16; Exh. AG 2-1 (Supp.). An important metric used both by the Department and the federal Department of Transportation in determining whether distribution and interstate natural gas pipelines are properly maintaining their systems is whether a natural gas company identifies its leaks and repairs them within a reasonable time period. Exh. AG-25-3; Exh. AG 2-33; RR-DTE-67; RR-DTE-71; Exh. DTE 3-12. The record demonstrates that the most dangerous, Type 3, leaks are repaired by Bay State, immediately. Exh. AG-25-5; Exh. AG 14-7. No party challenges that Bay State appropriately responds to the most dangerous Type 3 gas leaks.

The Department regularly looks to whether its jurisdictional gas companies are repairing Type 2 leaks by year end and what percentage remain to be repaired at year end. Exh. AG-14-19; Exh. AG 25-5; Exh. DTE 3-9. Exhibit AG-2-16 demonstrates that Bay State consistently repairs Type 2 leaks by year end. See also, Exh. AG-25-5; Exh. AG-14-18. Moreover, Bay State is in the top 20% of all gas companies in repairing Type 2 leaks by year end. Exh. AG 2-16; Exh. AG-14-19. In addition, in order to identify the location and nature of its Type 2 leaks, Bay State exceeds the requirements of federal and state codes in its leak surveillance program. Exh. AG-14-19; Exh. AG-25-5; Exh. AG-14-18. There is no evidence in this record that demonstrates that the SIR program was necessitated by a failure to maintain the system.

As Mr. Cote and Mr. Bryant both testified, with any asset supported by customers in rates, the Company has an obligation to extend the asset's life as far as possible into the future, taking into account the economics of repair versus replacement and more significantly, public safety concerns. Tr., at 275-80, 2004, 3290, and 3886. Premature retirement of an aging but otherwise safe main could impose unnecessary costs on customers.[19] Therefore, Bay State was careful to continually evaluate its leak trends and repair or replace affected mains as each individual circumstance required (as assessed by on-site field personnel through segment leak rate review and then unearthing and visually observing the main). Exh. AG 14-1; Exh. AG 14-19; Exh. AG-2-1. As the record demonstrates, in the winter of 2002-2003 it became apparent that the Company's ability to manage its leak rate through repair was being outstripped by the sheer number of leaks in its Brockton system and the impact that significantly colder weather had on its system. Exh. DTE 3-6; Exh. AG-14-3. That was the turning point when the balance tipped from repair to replacement for the remaining mains.

For all these reasons, the SIR does not constitute a "dangerous situation that the Company created for itself" as alleged by the Attorney General. AG Br., at 8. These broad brush assertions are not only inaccurate, they are irresponsible. Bay State's repair rates are only one piece of evidence that demonstrates Bay State's operational diligence and professionalism. Another is the number of miles of bare and unprotected steel that has been replaced by Bay State: since 1995, Bay State has replaced **130 miles** of bare steel and **213 miles** of coated unprotected steel, either by applying cathodic protection, replacing the mains with plastic or

[19] Moreover, the suggestion that Bay State delayed replacement in order to obtain recovery in this rate proceeding is incorrect and counter-intuitive. See, AG Br., at 8. Under that logic Bay State should have accelerated replacement during 2002 and 2003 in light of the rate freeze ending so it could capture the impact on its rate base of those additions fully in its 2004 test year non-revenue, non-discretionary plant additions, and then seek the recovery mechanism. The Attorney General attempted a variation of this argument with respect to Boston Gas Company's rate base in D.T.E. 03-40 that the Department found was not supported by the evidence. Neither of the Attorney General's contrived views of utility management decision-making is correct. Public safety and reliability are the most important drivers of infrastructure management.

cathodically protected steel, or abandonment. Exh. AG 14-1; Exh. AG 14-25; RR-AG-95. These numbers do not include the cathodic protection of hundreds and hundreds of miles of unprotected and bare steel pipe replaced between 1971 and 1995 in response to the requirements of 49 CFR Part 192 (the "Pipeline Safety Act."). See RR-AG-95.[20] Even after these replacement actions in recent years, Bay State must still replace the remaining 582 miles of bare and unprotected coated steel in its system.

The Attorney General also alleges that Bay State's field repair crews are instructed to fix leaks using clamps rather than replace the mains. AG Br., at 20 (attributed to a testifying Local 273 employee[21]). Mr. Cote testified that leak crews are equipped to repair Type 2 leaks. Tr., at 2379, 2457-59, 3454, and 3654-3737. They use clamps for this purpose because that is considered good utility practice in order to eliminate the public safety risk of a leaking natural gas main. See, Id.; Exh. AG-6-1. Following a repair, the field crews and their supervisors make recommendations as to whether the pipe should be replaced.[22] If the recommendation is approved, a contractor crew is assigned the replacement because the replacement can be accomplished economically. Id. There is nothing irregular about this process.

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[20] The Attorney General is attempting to inject unnecessary confusion into the record, when he states that during 1985 to 1997, Bay State replaced unprotected steel at the rate of 46 miles per year. AG Br., at 20. However, the Attorney General misreads the evidence. 41 miles per year of the "replacement" activities reflect the reduction in the unprotected steel inventory because Bay State added cathodic protection – it did not abandon or replace the unprotected coated pipe.

[21] This evidence should be given less weight by the Department on the basis of bias and personal pecuniary interest; at one time field crew members (who are required to join Local 273) performed all replacement work in the field.

[22] Contrary to the Attorney General's assertion, while the Foreman's opinion is given due weight, more factors are included in the Operation Center Manager's decision on when to replace a pipe, including prioritization of resources in light of public safety requirements.

b. Bay State's Geographic Approach to the SIR is Reasonable

With regard to the Attorney General's complaint that the SIR should be "rejected" because it is "technically flawed," once again the record evidence does not support the Attorney General's allegations. In spite of the many explanations given by the Company of the basis for the geographic replacement program, the Attorney General continues to believe that a mild variation on the Company's former method of mains replacement, and that used in New Hampshire, is appropriate. AG Br., at 23.

Bay State initially considered its current repair or replacement method for use in the SIR program. Exh. AG-2-12; Exh. AG 2-56. This method replaces pipe based on a segment by segment approach where replacement projects may not be found geographically. Exh. AG 2-12. It worked well for unprotected and bare steel to this point, and it works well for certain mains decisions (e.g., cast iron replacement) in Massachusetts. Moreover, the Attorney General is correct that Northern successfully used this approach in New Hampshire. Northern is also employing it in its Southern Maine service area for cast iron replacement. Northern Utilities, MPUC, Docket No. 2004-813 (2004). It has proved successful to date, but is not appropriate to address the accelerating leak rates faced by Bay State on its unprotected steel system in Massachusetts.

The Attorney General's irrational adherence to a defensive rather than proactive approach to replacement contravenes principles of operations management and least cost provision of service. Mr. Cote testified that the decision to replace the Brockton system first reflected prioritization of needed replacements in a broad, system-based context. Exh. AG 2-56; Exh. AG

2-12. Mr. Cote also stated that all Type 2 and Type 3 leaks will be repaired on the same basis as they are today. After that, and for all the reasons stated above, the geographic area replacement achieves replacement at a lower cost, with more efficient use of resources, with competitive bidding of both labor and materials,[23] and with significantly less inconvenience to the public. The geographic method was not used by Northern in New Hampshire because of the small amount of bare and unprotected steel that needed to be replaced for safety considerations based on leak rates evaluated at that time. By contrast, Bay State must replace over 500 miles of unprotected pipe. Chasing leaks, as the Attorney General suggests, will drive up O&M costs and replacement costs. Managing leaks through a systematic area-based mains replacement, as Bay State advocates, will lower O&M costs and replacement costs.

c. Technical Difficulties

The Attorney General's last objection is that Bay State's SIR "suffers from additional technical problems which render it an unreliable regulatory approach." AG Br., at 26. The SIR is not a "regulatory approach;" it is an operational approach. It is already underway, and by no means a hypothetical proposal as the Attorney General implies.

The Attorney General points to the fact that Bay State did not conduct a "root cause analysis" as suggested by his witness, as though the limited consulting activity by the witness was an adequate substitute for the comprehensive analysis done over a multi-year period by the

[23] Bay State has many years of operational experience behind its determination that the bidding of the larger project work will produce greater cost savings. The Attorney General's claim that a course of aggregated "segment" bidding will produce the same or similar savings has absolutely no evidentiary support on this record and must be dismissed. See, AG Br., at 25.

Company's experienced operations personnel, with the results confirmed by the independent engineering consulting firm, RJ Rudden.[24] Compare, AG Br., at 26 with Exh. AG 14-19, Exh. AG-2-16. It is not difficult to determine that the cause of the widespread and increasing system leakage is corrosion. RR-DTE-15-17; Exh. DTE 18-23; Tr., at 286-90; 3909, 2370-78. This is the cause reported on an annual basis to the DOT's Office of Pipeline Safety and the Department's Gas Safety division, in compliance with federal reporting requirements. Tr., at 3909-21, 3378. The evidence also indicates that corrosion is the leading cause of safety risks to distribution systems. Exh. BSG/DGC-17 (Report to Congress). A number of state regulatory agencies have already mandated bare and unprotected steel replacement for some or all of the gas companies operating in their jurisdiction. Exh. DTE 5; Exh. DTE 2-16.

A root cause analysis, as suggested by the Attorney General's witness, would an exercise producing no new information and providing no value to Bay State or its customers. <u>See</u> Tr., at 287-90; 3623, 3724. Also Bay State's determination that the program commence in Brockton does not require any additional analysis. The Brockton division has 63% of all the bare and unprotected coated steel mains in the Bay State system. Bay State's projected spending for SIR replacement reflects the level of expenditures that Bay State believes it can effectively manage in any given year of replacement. Exh. BSG/DCG-1, pp. 26-27. A root cause analysis would not change this assessment, but unnecessarily add to the cost of the SIR program.

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[24] The Attorney General claims the RJ Rudden report is "biased" because it recommends spending "in the range" of what informal meeting notes seem to indicate the Company "directed" it to identify. AG Br., pp. 27-28. There is no evidence presented by the Attorney General that RJ Rudden, a nationally recognized firm, would endanger its professional integrity by altering its conclusions to meet a purported demand of a single client. The accusation is offensive and without merit. There is no evidence of bias in the RJ Rudden report.

2. Response to DOER

DOER does not object to the SIR program. Tr., at 2866. It only objects to the rate recovery mechanism on the grounds that the program is inconsistent from a regulatory standpoint with the Company's proposed PBR. DOER Br., at 8. Bay State will respond to DOER's SIR objections in its PBR analysis, supra.

E. SIR Summary

Bay State's SIR program constitutes a major non-discretionary program. Replaced facilities will constitute material, non-discretionary, non-revenue producing replacements that must be undertaken to ensure the integrity of the Company's operating system, maintain system reliability and preserve public safety. The revenue recovery mechanism to address the incremental costs of this program is reasonable, cost-effective for the Department and the Company and relatively simple to administer. Accordingly, Bay State requests the Department grant it the authority to recover SIR program costs under the proposed ABRAM.

VI. SUMMARY OF REVENUE REQUIREMENTS

A. Revenue Requirements Analysis

Bay State determined the cost it incurs to serve its customers based on calendar year 2004 test year data, pro formed and adjusted for known and measurable changes. Exh. BSG/JES-1, pp. 5-7. By comparing the cost-to-serve against adjusted test year revenues, Bay State determined a revenue deficiency and the revenue requirement needed to make up that deficiency. Id. Bay State, therefore, employed a method consistent with the Department's requirement that utilities be permitted an opportunity to recover the reasonable costs incurred to serve customers and to earn a fair return on the property it has invested in its public service undertaking. Boston Edison Company, D.P.U. 906 (1982); see also Duquesne Light Company v. Barasch, 488 U.S. 299, 307 (1989). In calculating rate base, operating revenue and operating expenses, Bay State reviewed historic test year data for the 12-months ending December 31, 2004 pro formed for known and measurable changes, in order to determine normalized revenues and expenses for establishing rates. Exh. BSG/JES-1, pp. 5-8. Pro forma adjustments to the test year were based upon either known and measurable changes in revenues and expenses, or upon charges that will become known and measurable consistent with Department precedent. Id. Some expense adjustments reflect changes that will be experienced during the proceeding or during the rate year, December 1, 2005 through November 30, 2006. Exh. BSG/JES-1, p. 8; eee Massachusetts American Water Company, D.P.U. 88-172, at 7-9 (1989); Bay State Gas Company, D.P.U. 1122, at 70-72 (1981).

B. Bay State's Requested Base Rate Relief

Based on a 2004 test year cost of service, as compared to adjusted operating revenues, Bay State has a revenue deficiency of $22,238,326, based on an overall rate of return of 9.05% and known and measurable adjustments to test year revenues, expenses and rate base. Exh. BSG/SHB-1, pp. 4 -5; Exh. BSG/JES-1, pp. 5, 9-10; Exh. BSG/JES-1, at Sch. JES-2. Bay State's total revenue deficiency of $22,238,326 consists of a deficiency of $23,676,423 for the distribution function and an excess of $1,438,095 for the production function. RR-DTE-142.

The final functional allocation of the revenue deficiency will be performed at the time of Bay State files its reply brief.

VII. REVENUE REQUIREMENTS

A. Rate Base

Bay State's test year rate base is $397,106,628. Exh. BSG/JES-1, p. 5; Exh. BSG/JES-1, Sch. JES-2. In applying the test year level of rate base, Mr. Skirtich employed the actual per books amounts for rate base as of the end of the test year for Utility Plant in Service, Reserve for Depreciation and Amortization, Reserve for Deferred Income Taxes and Customer Deposits. Exh. BSG/JES-1, Sch. JES-2. All included plant is used and useful and in service of Bay State's customers. The level of inventories included in rate base is based upon the average of the 13 month-end balances of the test year. Only limited pro forma adjustments were made to the test year rate base, and each is described below.

1. Utility Plant in Service, Plant Additions and Capital Improvements

Bay State expended more than a half a billion dollars, $513,234,784, in gas utility gross plant additions since its last base rate proceeding in 1992. Exh. BSG/DGC-1, p. 63. Mains accounted for $163,191,824 or 31.9% of the total. Services accounted for $120,895,159 or 23.6% of the total. Miscellaneous Intangible Plant Additions accounted for $54,198,875 or 10.6% of total gross plant additions. The remaining balance of the total gross plant additions made between 1992 and 2004 - $174,220,926 – or 33.9%, are associated with the other remaining plant accounts. See Exh. BSG/DGC-1, p. 63; BSG/DGC-7.

a. Non-Discretionary Mains Account

Non-discretionary, non-revenue producing plant refers to "plant additions primarily intended to meet a utility's continuing service obligation to its customers." Boston Gas Company, D.T.E. 03-40 at 63. The costs must be prudently incurred and the resulting plant must be used and useful to ratepayers. Id. at 67. A utility must undertake a cost benefit or needs analysis, especially in the case of large, multi-year projects, and demonstrate that cost containment measures were undertaken, to support inclusion of non-discretionary plant in rate base. Id. at 68. For mains projects in particular, a demonstration of the cause of any cost overrun, accompanied by evidence of the utility's vigilant containment of cost, is paramount. Id.

As part of its initial filing, Bay State identified each non-discretionary project closed to plant Account 367 (Mains) between year-end 1991 and year-end 2004, the test year, that were greater than $100,000. Exh. BSG/DGC, p. 41; Exh. BSG/DGC-8. Bay State also provided, in discovery, detail on each non-discretionary project closed to plant Account 367 (Mains) greater than $50,000. Exh. DTE-3-21 (Revised); Exh. DTE-3-21 (Supplement); Exh. AG-1-19 (Revised) (Section 1). The record includes detailed summary that provide the year the project was undertaken, the name of the project, the location of the project (e.g. city/town), a description of the project location (e.g. street name), the actual indirect and direct (total) main costs, the actual direct main costs, the comparative estimated direct main cost, the dollar amount of any variance between estimated and actual direct cost, and the percentage of how much the actual cost deviated from the initial or recorded estimate. Id. The Company also justified any deviations greater than 10% between the actual and estimated expense. Id.

i. Response to Attorney General

The Attorney General contends that the Company undertook the non-discretionary projects for which it seeks rate base treatment with no regard for containing or mitigating costs to ratepayers. AG Br., at 48. The Attorney General therefore recommends that the Department disallow the amount of the discrepancy between the actual and estimated expense for all non-discretionary projects listed on Exh. DTE-3-21 (Revised); Exh. DTE-3-21 (Supplemental); Exh. AG-1-19 (Revised) (Section 1).

The Attorney General's recommendation is inconsistent with the record evidence and should be rejected. Bay State has contained costs on non-discretionary projects, and the cumulative evidence in the record provides "clear and cohesive reviewable evidence" on the requested additions. See, Massachusetts Electric Company, D.P.U. 95-40 (1995); Boston Gas Company, D.P.U. 93-60 (1993); Berkshire Gas Company, D.P.U. 92-210 (1993).

In addition to the detailed cost and variance information provided in Exhibit BSG/DGC-8, Exhibit DTE-3-21 (Revised), Exh. DTE-3-21 (Supplement), and Exh. AG-1-19 (Revised) Section 1, Mr. Cote testified that Bay State actively negotiates permit conditions in order to obtain the most favorable and cost-efficient terms. Tr., at 3394. He also testified that the Company regularly meets with officials of the affected cities and towns in order to discuss the costs incurred in maintaining Bay State's distribution system and how the decisions of municipal officials impact the costs to Bay State's customers, who are the city's and/or town's residents. Tr., at 3399. Bay State competitively bids all jobs over $50,000. RR-AG-87; Tr., at 2450. Jobs over $50,000 are bid on unit prices, not time and materials.[25] Each job has an assigned inspector who represents the Company's interests on the job site.[26] Large project bid processes require soliciting bids from four to eight approved bidders, with the exact number dependent on work location. RR-AG-87. Bid packages for such projects include a date for a site walk-over with a Company representative so that all bidders receive the same information. Id. While contractors do not bid on the basis of time and materials, Bay State allows reasonable charges for unforeseen conditions. Tr., at 2448. This is the primary basis for any variance. See, Exh. DTE-3-21 (Revised); Exh. DTE-3-21 (Supplemental); Exh. AG-1-19 (Revised) Section 1; Tr., at 3463.

b. Revenue Producing Mains Account

For revenue producing plant additions, the Department requires that a benefit/ cost analysis with pre- and post-construction internal rates of return ("IRR") be calculated. Boston Gas Company, D.T.E. 03-40 at 57. These analyses assist the Department in determining whether it was reasonable for a utility to commence the project based on the IRR calculated at the time, and whether the company prudently continued with the project if and when it appeared that the costs incurred no longer supported the initial IRR. Id. at 51, 54.

As part of its initial filing, Bay State identified each revenue producing project closed to plant Account 367 (Mains) between year-end 1991 and year-end 2004, the test year, that was greater than $100,000. Exh. BSG/DCG-1, p. 43; Exh. BSG/DGC-9. Bay State also justified

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[25] Time and materials awards give contractors no incentives to control costs.

[26] Contractors receive a daily inspector field report, documenting each day's work and noting extra charges allowed for that day. A copy of the inspector's field report is submitted with the contractor's invoice, documenting the charges. Tr., at 3721; Tr., at 2450.

with closing reports all the revenue producing plant in Account 367 (Mains) greater than $50,000. Exh. DTE-3-22 (Revised); Exh. DTE-3-27 (Revised).[27]

Over the years, Bay State undertook several initiatives to improve the revenue producing plant evaluation process, which resulted in changes being made to input calculations (e.g., O&M costs per customer, marginal capital costs and the like), project parameters (e.g., project life projection), and internal hurdle rates (e.g., weighted average cost of capital and risk-adjusted discount rates). Exh. BSG/DGC-1, p. 43. During this time, the relevant IRR changed based on new economic data. Tr., at 399; Exh. DTE-3-23. For revenue producing projects the actual cost (with limited exceptions) were in line with expectations.

i. Response to the Attorney General

The Attorney General recommends that the Department exclude from rate base those projects for which Bay State provided no reports regarding the incurred variance between estimated and actual cost. AG. Br., at 45. The adjustment proposed would remove $762,210 from Bay State's rate base. The Attorney General also recommends that the Department exclude additional projects amounting to $4,474,078 because there were variances between the estimated cost and the final actual cost. AG Br., at 46.

With regard to the first adjustment, it is completely unwarranted. The record is clear that although the Company tracks project cost, it does not require formal detail cost overrun write-up

[27] For each List Item on Exh. BSG/DGC-9 (Revenue Producing Projects (Account 367)) and on the schedules for Exhibit DTE-3-22 (Revised) and Exhibit DTE-3-27 (Revised), Bay State provided the Department with a summary that includes a variety of information, including the year the project was commenced, the Project ID and location description, the pre- and post- IRR calculations, comments applicable to the project, particularly with regard to cost variances, the estimated cost of the project, and the actual final cost.

reports for projects where final cost exceeds budget by less than 10%. It is common practice in the industry to balance the cost/benefit of tracking cost variances by setting a threshold limit on cost variances. See, Exh. BSG/DGC-1, p. 42; Exh. DTE-16-19; Exh. DTE-16-13. For the five projects in question, all had cost variances under the 10% threshold limit. The total cost overrun for the five projects was $18,347 for an average of less than $3,700 per project or a 4.7% cost overrun. See Exh. DTE-3-22 (Revised); Exh. DTE-3-27 (Revised); RR-DTE-136.

Moreover, as shown on Table BSG-1, the Company more than offset the cost overruns by exceeding the projected number of customer additions, load addition or revenue additions, which resulted in all but one of the projects providing benefits to ratepayers by yielding post construction internal rates of return greater than the Company's weighted cost of capital and internal hurdle rate. See Exh. DTE-3-22 (Revised); Exh. DTE-3-27 (Revised); RR-DTE-136; Tr., at 384.

Table BSG-1

Project ID	Variance	Overrun in $	ROR
L99D0052	2%	$2,574	10%
B98D0093	4%	$3,361	11%
L95D0023	7%	$4,672	16%
B94D0068	9%	$5,832	1%
B94D0101	4%	$1,908	14%
Total	4.7%	($18,347)	

With regard to the Attorney General's second proposed rate base disallowance of revenue producing plant, Bay State notes that of the 14 projects that the Attorney General questions, ten (10) have rates of return that exceeded the Company's weighted average cost of capital and internal hurdle rate and are in service providing benefits to ratepayers. See Exh. DTE-3-22 (Revised), Exh. DTE-3-27 (Revised); RR-DTE-136. For four projects, the evidence indicates that factors outside of the Company's control or unforeseeable to the Company, based on the information available at the time of estimating the project, both costs and customer related, attributed to project rates of return below the internal hurdle rate. See Exh. DTE-16-9, p. 7; Tr., at 386. Nevertheless, the Company's cost control measures, such as bidding all jobs over $50,000, having bids based on unit prices (not time and materials), and assigning a Company inspector to each project were in place on each job. RR-AG-87; Tr., at 2450, 3463, 3721.

Uncontrollable, unforeseeable outside factors contributed to the cost overrun of $201,713 for the four projects below the expected hurdle rate. Exh. DTE-3-22 (Revised); Exh. DTE-3-27 (Revised). The vast majority of the projects about which the Attorney General complains exceeded the internal hurdle rate for post-construction returns, even if the cost estimating process resulted in a variance from actual cost due to unforeseen factors. See, Exh. DTE-3-22 (Revised); Exh. DTE-3-27 (Revised). However, this record does not contain evidence of imprudence.[28] This record shows that even when reasonable steps are taken to provide accurate cost estimates,

[28] The Attorney General alleges that a 20% overrun demonstrates an inability to control cost. AG Br., at 47. In fact, construction contingencies normally run in the range 25%. Since these are estimated internally, none of Bay State's initial estimates leave room for contingencies. In light of this, it is reasonable to conclude that the Company is effective at controlling cost.

factors can arise that will change the final actual cost. All of Bay State's plant additions provide clear and cohesive evidence of Bay State's cost containment efforts and reasonableness of its decision-making with respect to each project.

ii. Masspower/Monson Palmer Extension

In 1987, Bay State informed the Department of its interest in installing a main to serve the communities of Monson and Palmer, in the event a line was built to serve Masspower. Exh. BSG/DGC-1, p. 49. Bay State conducted extensive financial analyses to determine that the expansion project was economically feasible under multiple scenarios. Exh. BSG/DGC-1, p. 49; Exh. DTE-16-27.

Masspower is an electric generating station that commenced commercial operation in July of 1993. It is a 267 megawatt combined-cycle cogeneration facility fueled by natural gas. Exh. BSG/DGC-1, p. 49. Building facilities to serve Masspower also gave Bay State the ability to bring natural gas distribution service to Monson and Palmer. Exh. BSG/DGC-1, p. 50. Bay State received Department approval and the approval of the Massachusetts Energy Facilities Siting Council to build the facilities. Exh. BSG/DGC-1, p. 50; Exh. MP-1-10.

The extension project allowed Bay State to run two extension lines to serve the Masspower generating facility in Palmer and "a to be constructed" distribution system serving customers in the towns of Monson and Palmer. Exh. BSG/DGC-1, p. 50. One portion of the construction was known as the "Main Line." The Main Line construction consisted of laying 18.6 miles of a 16 inch high-pressure steel line originally to serve the needs of the Masspower facility, and subsequently has been used also to serve Massachusetts Municipal Wholesale

Electric Company ("MMWEC"). Exh. BSG/DGC-1, p. 51. The line runs from the Tennessee Gas Pipeline interconnect in Monson to the Masspower facility, located in the Indian Orchard section of Springfield, and serves the MMWEC facility in Ludlow, off an interconnection built and paid for by MMWEC. Exh. BSG/DGC-1, p. 51.

The "Distribution Line," consisted of a 4 inch plastic pipe, along side of, and at the same depth and in the same trench as, the 16 inch Main Line. Exh. BSG/DGC-1, p. 51. This system runs 22 miles in total, through the towns of Monson, Palmer and Wilbraham, in order to serve Bay State's Monson-Palmer distribution systems. Exh. BSG/DGC-1, p. 51. Finally, the project included a gate station in Monson to take deliveries off of the Tennessee Gas Pipeline. These lines were placed in service in a two-year period, from late 1992 through 1994. Exh. BSG/DGC-1, p. 51.[29]

The gross plant investment by Bay State, between 1992 and 1994 was $22,448,367 for the 16 inch Main Line and 4 inch Distribution Line with $6,407,604 in accumulated depreciation for a net plant total of $16,042,396. Exh. BSG/DGC-1, p. 53. In addition to the Main Line and Distribution Line, Bay State made, from 1992 to 2004, gross plant investments of $3,274,027 with $933,996 in accumulated depreciation for a net plant total of $2,199,676 for laterals off the 4 inch Distribution Line. Exh. BSG/DGC-1, p. 53. The total gross plant and net plant amounts for the 16 inch Main Line, 4 inch Distribution Line and Distribution Laterals is $25,722,394 and

[29] As of December 2004, Bay State is serving over 190 residential customers and 90 commercial and industrial customers from the 4 inch Distribution Line. Between 1992 and 1994, Bay State constructed several significant laterals known as the Ware Street, Sykes Road, Park Street and Palmer Street lines off of the 4 inch Distribution Line. Exh. BSG/DGC-1, p. 51.

$18,380,794, respectively. In 2004, the 16 inch Main Line, 4 inch Distribution Line and Distribution Laterals plant provided net operating income of $1,231,489 and yielded a return of 9.44% compared to a Weighted Average Cost of Capital ("WACC") of 8.41%. Exh. MP-1-30.

Bay State seeks inclusion of the net plant associated with this project in rate base as part of this proceeding.

No party has challenged this request.

c. Non-Discretionary Non-Mains Account

In its initial filing, Bay State identified each non-discretionary project closed to plant accounts other than Account 367 (Mains) and Account 303 (Misc. Intangible Plant) between year-end 1991 and year-end 2004, the test year, which were greater than $100,000. Exh. BSG/DGC-1, p. 45; Exh. BSG/DGC-10. Bay State also provided in discovery all non-discretionary non-mains additions greater than $50,000. Exh. DTE-3-25; Exh. AG-1-19 (Revised) Section 2. Bay State's rate base includes the net plant amounts associated with gross plant additions for non-discretionary capital expenditures necessary for Bay State's natural gas operations, such as LNG facility purchases, capital upgrades to facilities (repiping; perlite installation; liquefaction equipment; regulator equipment), odorant storage; construction of regulators, filters and control lines. Exh. BSG/DGC-1, 45; see, Exh. BSG/DGC-10. Included in this plant account are categories of capitalized office and communications equipment that are required for Bay State to administer its general, managerial, customer support, and operations functions. Exh. BSG/DGC-1, p. 45.

No party challenged inclusion of non-mains non-discretionary plant additions in Bay State's rate base.

d. Intangible Plant Account

As shown on Exh. BSG/DGC-11, Bay State's Miscellaneous Intangible Plant Account 303 includes SCADA software, EASy billing system requirements, Customer Information System ("CIS"), WOMS enhancement, Voice Mail, Client Server networking, Voice Recording for customer service enhancement, and various corporate services additions. Each of these technology functions is currently assisting Bay State in meeting its customer needs. Exh. BSG/DGC-1, p. 46; see also, Exh. DTE-3-26; RR-DTE-109; RR-DTE-113. A number of the additions to this plant account were necessary additions for operational reasons. For example, SCADA provides real time monitoring and control of the distribution system. Exh. BSG/DGC-1, p. 46; RR-DTE-109; Exh. BSG/DGC-11. The EASy system is an off-system gas management application that captures gas contracts, trading, capacity release, storage, scheduling, and accounting associated with upstream pipeline capacity. Id. Gas nominations are scheduled through EASy, electronically submitted and confirmed with pipelines via electronic database interaction processing. Id. Transportation capacity, operational balancing agreements, storage activity and inventories are monitored and managed through EASy. Id.

A number of additions to this account reflect increased attention to the technology that aids Bay State in better serving its customers. For instance, Bay State installed the Panagon bill image viewing system for Customer Service Representatives ("CSR") in mid 2002; the CallAid CSR on-line knowledgebase; improved integrated voice response system ("IVR") in April 2003;

electronic fax capability; Geneysis CTI, to permit information to be relayed to active CSRs through screen pops; TargetVision monitors to relay to CSRs current popular news and internal NiSource information; Call Recording (NICE) technologies, automated call back system, and web self-serve functionality. Exh. BSG/DGC-1, p. 47; Exh. BSG/DGC-11.

The CIS was installed for Bay State in November 1999 to meet the mandates of Y2K compliance. Exh. BSG/DGC-1, p. 54; Tr., at 2528; RR-DTE-113. The previous CIS, a legacy system, was exceptionally difficult to upgrade for any purpose and posed a threat to the integrity and continuity of Bay State's operations and administration in the face of the Y2K concerns. Exh. BSG/DGC-1, p. 54; RR-DTE-109. The CIS installed and active since 1999 is a broad-based customer information system that supports the collection, processing, storage and retrieval of customer service data for Bay State's 285,000 customers and those of Northern's 50,000 customers. Exh. BSG/DGC-1, p. 54. The system integrates information exchange and retrieval for numerous operational activities that are part of the customer service requirements. The logic contained in the CIS supports customer meter reading and history; billing and logs of billing inquiries; solutions for payment options; accounting and adjustment processing and recording; service order scheduling and execution; credit and collections functions, including account holds and customer contact logs; meter and service line information; usage history; premise and marketing information; and variable customer information requirements. Exh. BSG/DGC-1, p. 55; Exh. BSG/DGC-11, p. 1. Included in the investment is Bay State's cost of converting the legacy information (called CIS Pro-Edits) and the CIS Enhancements for meter-to-cash collections. The CIS enhancements for meter to cash improve the functionality of customer bill collection processes and supporting information, including an upgrade to the new release of the Customer Statement Format Design system, which supports Bay State's new bill format. Id.

In order to control costs associated with information technology, all projects proposed in a budget year are critically reviewed and are prioritized as Priority 0 through Priority 3, with Priority 0 being mandatory, or of the highest priority. Exh. BSG/DGC-1, p. 47. NCSC IT Directors review all IT capital projects. Exh. BSG/DGC-1, p. 48. NiSource's Chief Information Officer reviews all IT capital projects exceeding $100,000. Exh. BSG/DGC-1, p 48. All IT projects that are greater than $300,000 and that have gone through the IT review process and designated as Priority 0 (or high priority) are required to be supported by a complete business case analysis. Exh. BSG/DGC-1, p. 48. The NCSC Financial Planning department reviews all business cases before approving a budget for an IT project. Exh. BSG/DGC-1, p. 48. The business case is comprised of five sections: Project Description & Fact Sheet, Impact Analysis and Dependencies, Economic Analysis, Risk Analysis, Benefit Justification, and Signature Approvals. Exh. BSG/DGC-1, p. 48. Economic Analysis section consists of a package of cost estimation worksheets and a financial model that calculates several financial metrics such as an IRR, Net Present Value (NPV), and Net Operating Profit After Tax (NOPAT) for both a worst case and a best case scenario. Exh. BSG/DGC-1, p. 48. Business case development efforts are supported with project management training material, templates, guidelines and approval limits information accessible to each employee through the NiSource intranet site. Exh. BSG/DGC-1, p. 48.

Because these plant additions were planned in a manner that constrained costs and because they are used and useful in service to customers, Bay State seeks their inclusion in rate base.

i. Response to Attorney General

The Attorney General seeks a $21,546,059 adjustment to Bay State's rate base to remove Bay State's primary Customer Information System because, according to the Attorney General, it was not cost contained and there was a significant cost overrun.

The adjustment should be denied. To begin with, the Attorney General has grossly overstated the net plant that is in rate base. While the gross plant addition was $21,546,059, the net plant addition included in rate base is $11,182,919. Therefore the Attorney General has asked the Department to disallow $10,362,140 more than the net plant amount. For this reason, alone, the recommendation should be rejected.

However, even considered on its merits, prohibiting Bay State from recovering its investment in the CIS is completely unwarranted and improper and would result in a confiscation of Bay State's property in service for customers based on current standards. The record demonstrates that the Company needs the system, its decision to obtain an upgrade was necessary because of Y2K concerns, and the CIS continues to be used and useful in the service for the benefit of customers. See Exh. AG-3-16 (Supplement); RR-DTE-109; RR-DTE-113. The record evidence is clear, in particular supported by the study of the Meta Group, that the total investment made in Bay State's CIS system was reasonable compared to similarly sized gas utilities and resulted in a lower cost per bill issued on a forward looking basis. Therefore, Bay

State has demonstrated that customers will and do benefit from this plant addition in a manner that is a reasonable alternative to a traditional, pre-investment cost-benefit analysis. See, Boston Gas Co., D.P.U. 03-40, p. 54-56. The CIS plant addition meets the Department's standard and should be allowed in rate base.

Bay State did seek to contain costs, but this type of information system has a long history of creating implementation challenges for utilities. As described above, a significant review process is undertaken.

Accordingly, because Bay State has demonstrated that the total cost of its CIS was reasonable and that the system is in use daily on behalf of the Company and its customers, the Attorney General's recommended disallowance should be denied.

2. Adjustment to Remove Bay State/NIPSCo and Lawrence Goodwill

As shown on Exhibit BSG/JES-1, at Sch. JES-13, p. 2, Mr. Skirtich removed $445,906,987 from utility plant, account Miscellaneous Intangible Plant (Account No. 303), and $70,541,969 from accumulated Amortization of Intangible Plant. This removes the rate effect of goodwill on Bay State's books resulting from the Bay State/NIPSCo. merger and the Lawrence division acquisition. Exh. BSG/JES-1, pp. 47-48; Exh. BSG/JES-1, at Sch. JES-13, p. 2.

No party has challenged this adjustment.

3. Adjustment for Metscan Meter Reading Devices

Bay State adjusted year-end rate base for a portion of the Metscan devices that were on Bay State's books as of December 31, 2004. In order to reflect this adjustment, Mr. Skirtich eliminated from rate base the net plant balance and related deferred income taxes of the Metscan devices, reflecting the fact that the net book value of the remaining assets was transferred to a regulatory asset, consistent with Bay State's request to recover the cost over five (5) years as a part of this proceeding. Exh. BSG/JES-1, p. 48; Exh. BSG/JES-1, at Sch. JES-13, p. 3.

No party has challenged this adjustment to rate base.[30]

4. Adjustment for Completed Construction

As a general matter, the Department does not permit constructed plant to be included in rate base until it is in service to ratepayers. Interest during construction is recorded on the utility's books to compensate the utility for the time-value of money until the plant is in service. Construction work in progress, or CWIP, is an account that captures costs incurred in the design and construction of both revenue and non-discretionary rate base additions. Exh. BSG/JES-1, pp. 48-49. Once the plant is used and useful, the value of the costs accumulated in CWIP is moved into a plant asset account. Id. Amounts accumulated in CWIP represent actual costs incurred for the plant, so this value is integral to establish the total cost of utility plant. Id. See Exh. DTE-16-3. The amount was included in account 106 which is completed construction not classified.

At the end of the test year, Bay State had accumulated CWIP related to construction. Mr. Skirtich excluded these amounts from Bay State's rate base. Exh. BSG/JES-1, p. 49. However, Mr. Skirtich reduced the exclusion for plant that was in service but that, because of accounting lags, had not, at test year-end, been transferred to Utility Plant in Service. Id.; Exh.

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30 Bay State responds to other parties' challenges to Bay State's request to recover the remaining value of Bay State's Metscan investment and lease buyout payments later in this brief.

BSG/JES-1, at Sch. JES-13, p. 4. The adjustment to remove CWIP is $6,332,113. Id. The amount of CWIP that the Company proposes to include in rate base is $1,053,621. Exh. BSG/JES-1, Sch. JES-13, p. 4.

a. Response to the Attorney General

The Attorney General proposes that the Department deny the Company's proposed addition to rate base of CWIP. AG Br., at 48. The Attorney General argues that plant additions that have been completed by the end of the test year should appear in Account 106, Completed Construction Not Classified. AG Br., at 49. The Attorney General points to the fact that in Bay State's 2004 Annual Report to the Department, Account 106 has a zero balance. AG Br., at 50.

The Attorney General's proposed rate base disallowance is inappropriate and does not recognize the benefits that accrue to ratepayers by plant in service at the end of the test year. The Department's test year end ratio bare standard includes plant that is in service at the end of the test year in rate base. Bay State Gas Company, D.P.U. 92-1111, p. 64. It is the fact that the plant is in service, not the status of its accounting treatment that should control. Moreover, the evidence demonstrates that Account 106's zero balance does not reflect the reality of Bay State's CWIP because, as described in the record, the Company has not recorded entries to Account 106 since the end of 1992. See, Exh. AG-1-2; Exh. DTE-16-2. The Attorney General's suggestion is contrary to the evidence in the record and creates an arbitrary basis for disallowance of plant in service but not yet booked to a plant in service account. Exh. DTE 16-3.

5. Allowance for Other O&M Cash Working Capital

Cash working capital is the amount of capital that is needed by Bay State to fund the time period between the receipt of payment of utility service and the disbursements required to render that service. Exh. BSG/JES-1, pp. 51-52. The cash working capital component is divided into two components – (1) Purchased Gas, and (2) Other Operations and Maintenance ("O&M") expense to accommodate the recovery of the purchased gas component through the CGA and the Other O&M expense component through base rates. Exh. BSG/JES-1, p. 52. For the purposes of this proceeding, Bay State proposed a cash working capital allowance of $11,453,613 related to Other O&M expense to be included in distribution rate base. Exh. BSG/JES-1, p. 50; Exh. BSG/JES-1, at Sch. JES-13, p. 1. A Purchased Gas Cash Working Capital allowance was removed from the total cash working capital included in rate base for later recovery in Bay State's Cost of Gas Adjustment Clause ("CGAC"). Exh. BSG/JES-1, p. 53.

Department has repeatedly expressed concern over utility use of the 45-day convention for non-fuel O&M expense and has urged the use of cost-effective alternatives that reduce working capital. Boston Gas Company, D.P.U. 96-50 (Phase I), at 27 (1996); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 55 (2002); Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998); Exh. BSG/JES-1, p. 64, citing Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15. Because the Columbia Energy Group historically conducted lead lag studies on a regular basis for its distribution companies, this institutional knowledge was present at NCSC and therefore cost-effective internal resources were available to perform study. Exh. BSG/JES-1, p. 64; Exh. BSG/JES-2; Exh. BSG/JES (WP). Accordingly, as part of its preparation for filing its request for rate relief, Bay State asked Mr. Skirtich to prepare a lead lag study in order to update the net lag days associated with Purchased Gas working capital collected in Bay State's CGA, and to establish the net lag days to be used for Other O&M Expense working capital to be included in base rates. Exh. BSG/JES-2; Exh. BSG/JES (WP).

The study consists of schedules supporting the calculation of both lag and lead days for Purchased Gas Working Capital and for Other O&M Working Capital. Exh. BSG/JES-1, p. 52. The lead lag study produced a Purchased Gas net lag of 25.30 days, or 6.932% (25.3/365), and an Other O&M expense net lag of 42.21 days or 11.564% (42.21/365). Exh. BSG/JES-1, pp. 52-65.

No party has challenged the proposed allowance for cash working capital.

6. **Materials and Supplies Inventories**

Bay State included the 13-month average of materials and supplies inventories in rate base, consistent with Department precedent. Exh. BSG/JES-1, p. 50; Exh. BSG/JES-1, at Sch. JES-15. No party questioned the use of the average of 13-month inventories as the test year amount for inclusion in rate base.

B. Operating Revenue

Mr. Ferro calculated Bay State's test year billing determinants and test year revenues using accepted industry practices and consistent with Department precedent. Test year billing determinants represent the annual volumes of gas used and the total number of bills rendered during the test year and are determined for each customer class separately. The test year number of bills for all classes is 3,372,442. Exh. BSG/JAF-1, Sch. JAF-1-3, p. 4. The test year throughput for all classes is 609,712,995 therms. Exh. BSG/JAF-1, Sch. JAF-1-4, p. 9.

The current rates are applied to the test year billing determinants to establish the pro forma revenues. Total test year sales and transportation customer distribution revenues at current rates are $474,918,261. Exh. BSG/JAF-1, Sch. JAF-1-2. In addition, Mr. Ferro calculated adjustments to other gas operating revenues associated with reactivation fees of $34,855 (Exh. BSG/JAF-1, Sch. JAF-1-7), warrant fees of $25,540 and locksmith fees of $4,400. Exh. BSG/JAF-1, Sch. JAF-1-9.

1. **Unbilled Revenues**

Bay State's test year revenue reflects an unbilled volume adjustment of 5,317,171 therms. Exh. BSG/JAF-1, Sch. JAF-1-6, page 4. These unbilled volumes are used to determine the Company's calendar month volumes, which are then run through current rates to derive test year revenues. Exh. BSG/JAF-1, Sch. JAF-1-2. The purpose of determining revenue that reflects the unbilled amounts, which result in calendar month revenue, is to establish test year operating revenues that are most reflective of how the Company bills its customers for both distribution and gas supply service. Exh. BSG/JAF-1, pp. 13-14, Sch. JAF-1-2. Due to the billing cycle process employed by Bay State, on a monthly basis Bay State calculates and records unbilled revenue for the current month. The calculation of the unbilled revenues recorded in the test year is based primarily on the assumption that approximately half of the billing-cycle sales and non-daily metered transportation volumes occur in the current month, while the remaining volumes are billed the following month. Exh. BSG/JAF-1, pp. 13-14. Using the unbilled volumes to determine calendar month volumes and in turn applying those volumes to test year rates, Bay State corrects for any inaccuracy in the recording of unbilled revenue on the accounting books for the test year.

No party has questioned Bay State's unbilled revenues calculation on brief.

2. **Weather Normalization**

The weather normalization adjustment decreases Bay State's test year volumes by 13,993,508 therms. Exh. BSG/JAF-1, Sch. JAF-1-6. This volume adjustment decreases test year base or delivery service operating revenues by $2,555,582. Exh. BSG/JAF-1, Sch. JAF-1-5, p. 9. The resulting weather normalized volumes are applied to test year GAF rates (as well as distribution rates) to also determine weather normalized gas cost revenue.

Bay State prepared its cost of service analysis based upon "normal" weather. Consistent with Department precedent, Bay State determined normal by calculating the average monthly effective degree days ("EDD") over the last 20 years. Normal volumes are derived by applying the temperature sensitive therm use for each customer class grouping to the ratio of normal to actual EDD. The resulting normal temperature sensitive use is added to the base, or non-temperature sensitive, use to determine total weather normalized volumes. Exh. BSG/JAF-1, Sch. JAF-1-6. No party questioned Bay State's weather normalization calculation on brief.

3. **Test Year Revenues**

Pro forma revenues are calculated in Exh. BSG/JAF-1, Sch. JAF 1-2. Pro forma revenues are the product of customer charges times the number of bills plus the product of volumetric charges by volumes. The base rates utilized to calculate pro forma revenues are those approved by the Department in D.T.E. 97-97. Exh BSG/JAF-1, p. 34. The gas adjustment factor rates recover gas costs and represent the actual rates charged during the test period. The Local Distribution Adjustment Factor rates recover various items including conservation and remediation costs and also represent the actual rates charged during the test period. Exh. BSG/JAF-1, pp. 36-37. Total pro forma revenues equal $474,918,261.

The Company also calculated other revenue adjustments associated with changes to miscellaneous service fees. The fees are set forth in Exh BSG/JAF-3, Sch. 3-1 at M.D.T.E. No. 35, Appendix B-1. The revenue adjustment associated with an increase of $5.00 in the account reactivation fee to $20.00 will result in additional revenues of $34,855. Exh. BSG/JAF-1, p. 38. An adjustment to operating revenues of $7,270 is necessary to reflect the Company's proposal to charge customers the actual costs of a warrant. Exh. BSG/JAF-1, pp. 40-41. The Company also proposes to institute a locksmith fee, which would increase revenues by $4,400. Exh. BSG/JAF-1, p. 41. There is no revenue adjustment associated with the proposed increase to the meter test fee because there were no meter tests performed during the test period. Exh. BSG/JAF-1, p. 39.

4. **LBR Adjustments**

Bay State made three Lost Base Revenue ("LBR") adjustments to normalize test year operating revenues and to the manner in which LBR is collected. Exh. BSG/JAF - 3-1, p. 15. For the first, Bay State eliminated test year 2004 revenues related to the recovery of LBR in the amount of $1,224,180. Bay State recovers LBR through its Energy Efficiency Charge ("EFC"). The LBR included in the test year was calculated and recorded in accordance with the

Department's rolling period method. The adjustment is appropriate to recognize that Bay State will no longer recover these LBR revenues on previously installed energy efficiency measures. When the rates in this proceeding are set, LBR associated with energy efficiency measures will be built into Bay State's base rates based on the test year level of billing determinants that reflect the reduction in sales due to installed energy efficiency measures. Tr., at 3023-26.

The second LBR adjustment to operating revenue removed the extraordinary non-recurring LBR revenue associated with Bay State's exogenous cost recovery of LBR under D.T.E. 04-57 and D.T.E. 04-93. Exh. BSG/Rebuttal-1, p. 5.

The third change is to move recovery of the LBR from Bay State's energy efficiency charge of the local distribution adjustment charge ("LDAC") to the PBR mechanism. Exh. BSG/JAF-3, Sch. JAF-3-1.

a. Response to Attorney General

The Attorney General proposes an adjustment to Bay State's revenues relative to its Lost Base Revenue. AG Br., at 50. The Attorney General indicates that since the PBR is a price cap and that average prices, not revenues, are adjusted under a PBR, there is no need for a lost revenue or energy efficiency therm savings adjustment. AG Br., at 51, n. 30. Bay State disagrees. Precisely because the PBR adjusts average prices resulting from revenues generated by billing determinants suppressed or reduced by energy efficiency therm savings is why the Company should be authorized to recover lost revenues associated with such reduction in therms and associated revenues. See, Exh. BSG/JAF-3, pp. 30-31.

5. <u>Response to Intervenor Concerns Regarding Revenue</u>

a. Dual-Fuel Revenues

Both DOER and MOC assert a lack of "cost support" for the Company's Dual Fuel Tariff proposal. DOER Br., at 11-12; MOC Br., at 15-16. The claim is without merit. Bay State used the Department's standard, of requiring a minimum annual revenue for providing firm distribution service, of long run marginal cost. Exh. DTE-7-19.

The Attorney General claims that because he asked Bay State to calculate the additional dual fuel revenues from Bay State's proposed M.D.T.E. 67 *that would have been collected had the proposal been in effect during the test year*, the estimated amount constitutes "known and measurable" revenues to the Company and should be used to reduce Bay State's revenue requirement for the rate year. <u>See</u>, AG Br., at 52, citing RR-AG-57.

Unfortunately, the Attorney General's interpretation and application of the Department's long-held standard is incorrect. An estimate of future recovery based on a tariff that was not in effect for a year that precedes the rate year by almost 2 years for a group of customers that is fluid in number is not known, nor is it measurable. This is precisely the kind of revenue that comes from the ebb and flow of ratemaking, and this tariff change is not designed to raise revenue. It is designed to permit dual fuel customers to contribute to the fixed capacity costs from which they benefit, reducing the contribution and eliminating the cross subsidization provided by other firm customers. Exh. DTE-7-12; Exh. AG-9-26.

DOER cites perceived benefits to firm customers because dual fuel customers will switch to oil in the winter when gas prices are highest, displacing the need for additional higher cost gas supplies. However, Bay State's proposal is to ensure a recovery of distribution revenue from dual fuel customers only because the distribution capacity is reserved for all firm customers. M.D.T.E. No. 67; Exh. BSG/JAF-3, pp. 3-6. Even though these customers have access to an alternative commodity, they are firm customers; Bay State must still plan capacity for them all year, and especially in the peak season. Thus, the DOER's suggestion that "freed-up" commodity could reduce the demand cost is faulty; any Bay State capacity that goes unused simply causes a revenue deficiency that is eventually paid for by all firm customers. The dual fuel firm customers should share in the costs they create.

b. Special Contract Revenues

The Attorney General also recommends that the Department make a post test year adjustment for the inflation provision of Bay State's special contracts and the addition of a new special contract customer who was not taking service during the test year nor 2005. AG Br., at 54. The Attorney General recommends the Department require Bay State to flow through the contractual escalation revenues (AG Br., at 54) even though they fail to meet the standard for a significant post test year adjustment. Fitchburg Gas and Electric Company, D.T.E. 02-24/25, at 76 (2002); Boston Gas Company, D.T.E. 03-40, at 11 (2003). Since they fail the Department's standard for a post-test year adjustment, constitute normal ebb and flow and the adjustment is only an estimate based on the prior year usage (and therefore not known and measurable), the Attorney General's proposal should be rejected.

However, with regard to the new contract customer, the Attorney General will be pleased to know that Bay State has included the tariff volumes for the new special customer in the test year, thus serving to lower rates. Exh. BSG/JAF-2 at Sch. JAF-2-1, p.8. Further, the test year revenues for that customer were higher than expected with the discount during the rate year, meaning customers receive more of a credit to revenues than Bay State now believes experience will bear out. Nevertheless, the Attorney General's adjustment must be rejected. Any further adjustment to test year revenues for this customer would double count the revenue contribution the customer may reasonably be expected to make.

c. Energy Product and Service Revenues

The Attorney General argues that because the Company has increased certain fees and charges for several EP&S services during the test year and in 2005, an adjustment to the Company's proposed revenue requirements should be made for these fee increases. AG Br., at 74. The Attorney General claims the additional revenue from the increased fees will amount to $794,259 and that the Company's revenue requirement should be reduced by this amount as "known increases" to test year revenues. AG Br., at 74.

The Attorney General's proposed revenue adjustment is improperly computed, but more importantly, does not meet the Department's standard for an adjustment to test year revenues. That standard requires an extraordinary change from test year revenues beyond the normal ebb and flow of revenues. The Department has routinely declined to allow adjustments for revenue growth occurring after the test year, such as the result of load growth. <u>Bay State Gas Company</u>, D.P.U. 1122, at 47 (1982); <u>Massachusetts-American Water Company</u>, D.P.U. 88-172, at 9 (1989); <u>Boston Gas Company</u>, D.T.E. 03-40, at 27.

The Attorney General's proposed revenue adjustment does not amount to revenues outside the normal ebb and flow of revenues. Furthermore, the Company clearly indicated that the Attorney General's proposed revenue adjustment is not representative of the expected revenues from the EP&S fee increases in the rate year, since the test year volumes and customer numbers used in the Attorney General's adjustment are not representative of the declining conditions to be expected in the rate year. RR-AG-56, p. 1; Exh. AG-9-45. The Company indicated that it has experienced a reduction in the conversion burner rental business since the end of the test year, because the Company is no longer installing new residential rental conversion burners and conversion burners are no longer as attractive for residential homeowners because an increasing number of new heating systems are not suitable for conversion. Exh. AG-9-45. As a result, this program is expected to see an annual revenue decrease in the future. Exh. AG-9-45. The annual revenues associated with the fee for service repair program are also expected to decrease from test year leads due to a reduction in volume of service calls since the test year. Exh. AG-9-45; RR-AG-56. Finally, the Attorney General's proposed adjustment does not take into account any corresponding cost increases that may occur after the test year resulting from changes in the EP&S business. For these reasons, the revenue adjustment proposed by the Attorney General does not meet the Department standards for a post-test year revenue adjustment and should be rejected.

The Attorney General proposes to flow through the Company's LDAC certain estimated revenues in the amount of $221,908 he claims will be generated by EP&S fee increases by 2007. AG Br., at 54. This figure is simply a projection of revenue for 2007 that may result from the

Company expanding its Guardian Care service to include central air conditioning, and is not known and measurable. Exh. AG-9-47. The Attorney General's proposal neither meets the Department's standard for post test year revenue adjustments stated above, nor is there any precedent for flowing a single potential revenue increase such as this through the LDAC under the PBR price cap index.

C. Operating and Maintenance Expense

1. Introduction

In the test year, Bay State incurred $99,007,484 in O&M expense. Exh. BSG/JES-1, p. 11; Exh. BSG/JES-1, at Sch. JES-1, Col. 1, Line 4. After recognizing corrections/adjustments to the test year, Bay State's O&M decreases by $37,945. Exh. BSG/JES-1, at Sch. JES-6, p. 1, Col. 1, Line 20.

2. Adjustment to Payroll, Wages and Benefits; Changes to Pension/PBOP

a. Introduction

In determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its employee compensation decisions result in a minimization of unit-labor costs. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 90; (citing Boston Gas Company, D.P.U. 96-50 (Phase I), at 47)). In order to evaluate the reasonableness of a company's total employee compensation expenses, the petitioner is required to provide comparative analyses of their employee compensation expenses. Boston Gas Company, D.P.U. 96-50 (Phase I), at 47.

Both (1) current total compensation expense levels and (2) proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly-skilled employees. Boston Gas Company, D.P.U. 96-50 (Phase I), at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 56 (1993); Bay State Gas Company, D.P.U. 92-111, at 102-03 (1992); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

b. Union Payroll

The Department requires, for a utility to seek an adjustment for payroll increases attributable to union contracts, that three conditions be met: 1) the increase will take effect before the midpoint of the first 12 months after the Department's order evidencing the rate increase; 2) increase is known and measurable (most often demonstrated by a signed contract); and 3) increase is reasonable. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 89; Boston Gas Company, D.P.U. 96-50 (Phase I), at 43; Massachusetts Electric Company, D.P.U. 95-40, at 20 (1995); Cambridge Electric Light Company, D.P.U. 92-250, at 35.

Bay State examined test year payroll amounts to determine whether they would be the same in the rate year or whether any known changes would occur. Exh. BSG/JES-1, p. 12. The adjustments made apply the known percent of payroll rate increase in 2005 and 2006 (to the midpoint). Exh. BSG/JES-1, pp. 12-13. Bay State has six separate bargaining agreements covering its union employees and the terms and annual increases vary. Exh. BSG/JES-1, p. 13;

Exh. BSG/SHB-2. Lawrence Local 326 was negotiated during the rate proceeding. Exh. BSG/JES-1, p. 13. The total union increase, including Lawrence Local 326, that is appropriate for inclusion in Bay State's revenue requirement is $1,243,031. See Exh. BSG/JES-1, p. 13; Exh. BSG/JES-1, at Sch. JES-6, page 2 ($1,173,418 + $57,157 + $12,456); RR-DTE-1; RR-DTE-18.[31] The reasonableness of Bay State's union payroll was confirmed by a number of comparative analyses conducted on Bay State's behalf by Mr. Barkauskas. Exh. BSG/SHB-1, pp. 8-10; Exh. BSG/SHB-1, at Schs. SHB-1 – SHB-9.

No party contested Bay State's payroll adjustment for union employees.

c. Non-Union Payroll

The Department has held, for a utility to recover an adjustment for non-union wage increases, the utility must demonstrate: 1) express management commitment to grant the increase; 2) a historical correlation between union and non-union increases; and 3) that the non-union increase is reasonable. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 89-90; Boston Gas Company, D.P.U. 96-50 (Phase I), at 42; Massachusetts Electric Company, D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

Non-union salary increases that are scheduled to take effect no later than 6-months after the date of the rate order may be included in rates. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 90; Boston Edison Company, D.P.U. 85-266-A/271-A, at 107 (1986). There

[31] The $43,234 and $9,422 reflect the amounts shown on RR-DTE-18 are net capitalization (i.e., 24.36%).

must be an historical correlation between union and non-union wages. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 91; Berkshire Gas Company, D.T.E. 01-56, at 56 (2002); Boston Gas Company, D.P.U. 96-50 (Phase I), at 42.

Bay State demonstrated that it carries an obligation for annual merit payroll increases as of March 1 of each year. Exh. BSG/JES-1, p. 13. The payroll adjustment reflects the annualization of the 2004 salary increases and the full March 1, 2005 merit increase. Exh. BSG/JES-1, p. 13. A merit increase of 2% is also confirmed for March 1, 2006 for non-union employees. Exh. BSG/JES-1, pp. 13-14. The total payroll adjustment for non-union employees is $443,840. Exh. BSG/JES-1, p. 14; Exh. BSG/JES-1 at Sch. JES-6, p. 2, Col. 2, Line 26. The reasonableness of Bay State's non-union payroll was confirmed by a number of comparative analyses conducted on Bay State's behalf by Mr. Barkauskas. See generally Exh. BSG/SHB-1.

No party contested Bay State's payroll adjustment for non-union employees.

d. Annual Incentive Compensation

The Department's long-standing precedent related to incentive compensation allows such expenses to be included in utility cost of service so long as such expenses are (1) reasonable in amount, and (2) reasonably designed to encourage good employee performance. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 99, citing Commonwealth Electric Company, D.T.E. 89-194/195, at 34. Reasonableness in incentive compensation design means the plan encourages good employee performance and results in benefits to ratepayers. Id. If the incentive compensation plan is tied only to financial performance, the benefit to ratepayers is unclear and the plan may be denied. Id.

Because in 2004 Bay State booked payroll accrual to match the incentive payments made to employees for 2003 performance, an adjustment was needed to remove the under-accrual from the test year. Exh. BSG/JES-1, p. 15. The revenue requirement reflects only the accrued payroll expense for 2004 at the first "trigger" level of the incentive compensation program. Exh. BSG/JES-1, pp. 15-16. Mr. Barkauskas demonstrated the reasonableness of Bay State's incentive compensation program and demonstrated that the plan is appropriately designed to incent good employee performance for the benefit of ratepayers. Exh. BSG/SAB-1, pp. 19-21; Exh. BSG/JES-1, pp. 15-16.

e. Adjustment for Medical and Dental Insurance

In general, test year health care (medical and dental) expenses and post-test year adjustments must be (1) known and measurable and (2) reasonable in amount. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 107; Boston Gas Company, D.P.U. 96-50 (Phase I), at 45-46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986). The Department requires utilities to contain their health care costs. Boston Gas Company, D.P.U. 96-50 (Phase I), at 46-47.

As is evident in every business sector, medical insurance costs continue to rise and many of the providers that insure Bay State's employees increased their rates after the end of calendar year 2004. Exh. BSG/JES-1, p. 16. The amount of medical and dental insurance in Bay State's revenue requirement includes the rates effective for 2005, the employee enrollment in January 2005 and the related employee contributions to the insurance plans. Exh. BSG/JES-1, p. 16. Bay State continually evaluates the coverage and premiums under its insurance programs as compared to the coverage and cost of market alternatives. Exh. BSG/JES-1, p. 17; Exh. BSG/SAB-1, pp. 40, 42. This ensures that Bay State's insurance cost is competitive and at the lowest level possible, given the market and the pressures of premium increases.

Bay State's adjustment for medical and dental insurance reflects known and measurable increases in health and dental insurance for its employees that have occurred in 2005. Exh. BSG/JES-1, p. 16; Exh. BSG/JES-1, at Sch. JES-6, p. 4. The calculation was made consistent with Department precedent. Exh. BSG/JES-1, p. 17. The proposed adjustment increases test year O&M expense by $741,045. Exh. BSG/JES-1, p. 16.

No party has contested Bay State's proposed medical or dental insurance adjustment.

f. Pension/PBOP Reconciliation Mechanism

Bay State has proposed a reconciling mechanism to recover its pension and post-retirement benefits other than pensions ("PBOP") expenses in a manner similar to that approved by the Department for the NStar Companies, Boston Gas Company, and Fitchburg Gas and Electric Light Company. The mechanism would establish an annual adjustment to recover the costs of Bay State's pension and PBOP obligations not being collected in base rates. Bay State has removed all of its pension and PBOB expense from base rates, and as such, all expense would be recovered through the LDAC. The mechanism is consistent with the pension and PBOP reconciling mechanisms approved by the Department for those companies. Commonwealth Electric Company, Cambridge Electric Light Company, Boston Edison Company, and NSTAR Gas Company, D.T.E. 03-47 (2003); Boston Gas Company, D.T.E. 03-40 (2003); Fitchburg Gas and Electric Light Company, D.T.E. 04-48 (2004).

The Department has recognized that there can be significant differences between the accounting and ratemaking treatment for pension and PBOP expenses which can have a large financial impact on the utilities under its jurisdiction. It has therefore determined that a pension and PBOP reconciling mechanism is appropriate if a company establishes the magnitude and volatility of its pension and PBOP expense, the accounting requirements and other external factors, rather than company actions, that affect the volatility of pension and PBOP expense, and the effectiveness of a reconciling mechanism to avoid the negative financial effect of pension and PBOP expense volatility. Fitchburg Gas and Electric Light Company, D.T.E. 04-48, at 19.

Bay State currently recovers its pension and PBOP obligations through the base rate approval granted in 1992 in D.P.U. 92-111. Id. at 46; Exh. DTE 8-10. During the test year, Bay State's pension expense was $3,182,669 and its PBOP expense was $2,447,613. Exh. BSG/SAB-1, p. 45.

Bay State's pension and PBOP obligations, and the values of its pension and PBOP plan assets, are subject to significant volatility caused by fluctuations in long-term interest rates and in the pension and PBOP trust asset investment returns. These factors are not within the control of the Company, but are largely dependant on the performance of the capital markets. Interest rates and capital market returns affect the value of the Company's pension and PBOP obligations, and the related trust assets, and significantly affect the expense recognized from year to year under Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions." Exh. BSG/SAB-1, pp. 47-48.

Over the past five years there has been significant volatility in Bay State's pension and PBOP expenses. Ex. BSG/SAB-1, p. 48; Tr. 1316, 1319. Although over the past three years the expenses have been more stable, over the most recent five-year period there have been large variations in pension and PBOP expense caused by variations in asset returns and interest and discount rates. For example, in 2001 qualified pension expense was a negative $616,000 (constituting income), whereas in 2004 it was a $3,832,000 expense. Exh. BSG/SAB-1, p. 48. Similarly, PBOP expense levels were not stable in the 2000-2002 period and have dramatically increased from 2001 to 2004. Id.; Exh. DTE 8-9. Discount rates and investment returns on pension assets, which have a large impact on pension obligations, have varied widely from 2000 to 2004. Id. Mr. Barkauskas testified that pension and PBOP expenses are "a long term proposition" and two to three years of relatively stable performance clearly is not indicative of future results. Tr. 1315-16; Exh. DTE 8-9.

The Company's proposed reconciling mechanism would establish a Pension/PBOP Expense Factor ("PEF") for pension and PBOP expenses. Any difference between the pension and PBOP expenses calculated in accordance with Generally Accepted Accounting Principles ("GAAP") and those amounts included in rates would be deferred and recognized as a regulatory asset or liability in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Amounts recorded as a regulatory asset or liability would be collected from, or returned to, customers as part of Bay State's Local Distribution Adjustment Clause (LDAC"). Exh. BSG/SAB-1, pp. 48-49.

The PEF is designed to recover the pension/PBOP expense moved from base rates to the LDAC. The difference between the current pension/PBOP expenses and the level moved from the Company's base rates into the LDAC will be amortized over a three-year period and reflected in the PEF. In addition, projected pension/PBOP expenses recovered through the application of the PEF will be reconciled with actual expense levels and matched against the actual recoveries, with any resulting over or under recovery being reflected as a credit or debit to the recoverable costs in subsequent periods. The Company would recover carrying costs on prepaid pension and PBOP amounts. Bay state will file the PEF annual adjustment factor for the upcoming year with each peak period LDAC filing, to take effect on November 1. Tr., at 1310. Exh. BSG/JAF-3, p.14; Exh. DTE 1-17; Exh. DTE 1-9; Exh. BSG/JAF 3-1, Tariff M.D.T.E. No. 37 §§ 5.01-5.10.

The PEF would ensure that Bay State's customers pay no more or no less than the prudently incurred costs associated with the Company's pension and PBOP obligations. It will also avoid future rate cases that could be attributable to these expenses. Exh. BSG/JAF-3, p. 14.

Under accounting rules, if a mechanism is in place that allows for probable recovery of pension deferrals over a reasonable period of time, the difference between the net charge resulting from the establishment of the additional minimum liability ("AML") and the amounts included in rates can be deferred as a regulatory asset under SFAS No. 71. Exh. DTE 1-11. If such a mechanism is not in place, the equity of a company must be written down for the difference. As part of its request for the PEF, Bay State asks the Department to grant it authority to recognize a regulatory asset for the amount of its current additional minimum liability and to adjust the regulatory asset for any future changes to the additional minimum liability. Bay State also seeks recognition that the Department intends to allow Bay State to establish a regulatory asset for the net amount of prepayments (funding the Company has made in excess of cumulative expense amounts recognized) made to the plan trust, and to allow for a reasonable rate of return in its LDAC to compensate the Company for the financing cost related to the prepaid amounts. Exh. BSG/SAB-1, p. 50; Tr., at 1319-21.

The Attorney General objects to the Company's pension and PBOP mechanism on the basis that its tariff formula is "not objective" and does not require deposit of funds collected into the respective benefit trust funds. AG Br., at 28. The Attorney General also does not believe there is a method to determine that rates established by the PEF tariff will be reasonable. In the alternative, if the Department approves the pension/PBOP mechanism, the Attorney General requests that the Department continue its practice of permitting discovery, hearings and briefs for each annual compliance filing. Id.

With respect to the Attorney General's concerns with the objectivity of the expenses, the pension and PBOP costs to be recovered in the Company's PEF tariff are all subject to the requirements of Generally Accepted Accounting Principles, in particular, SFAS No. 87 and No. 106, as well as review by the Company's accountants and actuaries. Therefore, there should be no concern about the calculation of pension and PBOP expenses. AG Br., at 29.

The Company will deposit amounts received through the PEF into the appropriate trust accounts. For PBOP, the Company will fund the trust based on the extent that a tax deduction is allowable for the funding in a particular recovery period and reasonable business judgment. For pensions, the Company will fund the trust to meet the minimum contribution amount required by law. Any additional pension contributions will be funded based on the extent that a tax deduction is allowable for the funding in a particular recovery period and reasonable business judgment. Exh. AG-24.

The Department will be able to review all of the Company's pension and PBOP filings, and therefore it will have ample opportunity to determine the reasonableness of the expenses before they are included in rates. The Company has no objection to continuation of the Department's practice of permitting investigation by all parties of its annual compliance filings. The Company would also be willing to submit reasonable documentation to support its annual filings as required by the Department.

The Attorney General has presented no convincing basis upon which the Department should reject Bay State's PEF. Therefore, the Company's proposed pension and PBOP expense reconciling mechanism should be approved.

3. Other Intervenor Concerns

a. Attorney General Claim that certain 2004 Performance Incentives were Severance Payments

The Attorney General references incentive compensation in the Company's 2004 annual report reflecting an employment agreement and a non-competition agreement. AG Br., at 65. The Attorney General states that under the terms of the employment agreement, a former Bay State employee was entitled to receive a substantial sum in 2004 as a "performance incentive" bonus, effective upon termination and with payments prior to the midpoint of the rate year. AG

Br., at 65. The Attorney General recommends that the Department disallow the 2004 portion of these payments and any associated capitalized amount and accrued liability contained in the cost of service because these expenses are severance payments, not performance incentive payments. AG Br., at 65.

Bay State disagrees with the Attorney General's recommendation. As the evidence demonstrates, payments were made in 2004, but the liability was booked to expense prior to the test year. Exh. AG-11-14. There is no cost in the cost of service related to this expense regardless of its name. Exh. AG-11-14.

4. Adjustment for Increases in Property and Liability Insurance Expense

According to Department precedent, companies must demonstrate that they have taken reasonable steps to control property and liability insurance costs, such as periodically bidding, performing benchmark cost analyses, and using a broker. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 162.

For Bay State, property and liability insurance coverage provides protection from casualty and loss and other damages that Bay State may incur in the conduct of its business. Exh. BSG/JES-1, p. 18. NCSC manages the NiSource corporate insurance program through which Bay State secures reasonably priced, comprehensive insurance coverage. The corporate insurance program includes both premium based and self-insured coverage, in order to obtain the most cost-effective loss premium portfolio. Exh. BSG/JES-1, p. 18. The record demonstrates that NCSC also relies on NiSource Insurance Company Limited ("NICL") to provide insurance coverage at a reasonable price included in the annual evaluation process that is undertaken to review exposures, premiums and coverage and to ensure the least cost insurance portfolio. NICL is not designed to make a profit; premiums are based solely on the cost of the risk. Exh. BSG/JES-1, pp. 19-20.

a. Response to the Attorney General

The Attorney General asks the Department to reduce the cost of service by $164,069 to reflect the capitalization of the Company's pro forma Workers Compensation Insurance Costs. AG Br., p. 80. The Attorney General states that Workers Compensation Insurance is a cost of employing labor in Massachusetts and that the Company failed to allocate any of its Workers Compensation Insurance cost to its construction activities. AG Br., at 79-80. Bay State disagrees.

As shown in Exh. Att. AG-1-27 (E), p. 1, the Company capitalizes Workers Compensation as a cost of labor. Workers Compensation is included in the overheads as indicated with Account 925-06 included in the calculation. Exh. Att. AG-1-27(E), p. 1. The Attorney General is correct that Bay State's filing should have adjusted the Workers Compensation amount, but at 24.36% of the adjustment for the insurance premium included on Schedule JES-6, page 5 and the self insurance adjustment for workers compensation included on Schedule JES-6, page 6, since Workers Compensation was capitalized for the test year. AG. Br. 79-80. The adjustment should be 24.36% times ($108,915), which is the $149,479, insurance premium increase less $258,394 self insurance reduction, or ($26,531) additional requirements.

Bay State will make this adjustment in its revised schedules, specifically Sch. JES-6, pp. 5-6, to be filed with its Reply Brief.

5. Adjustment for Self Insured Claims

Bay State self-insures the deductible portion of certain claims. Exh. BSG/JES-1, p. 20. Mr. Skirtich testified as to the following deductibles applicable to Bay State insurance: property damage – deductible of $1,000,000 per occurrence; auto liability, employee liability and general liability – deductible of $200,000 per occurrence; crime – deductible of $500,000 per occurrence; D&O – deductible of $10,000,000 per occurrence. Exh. BSG/JES-1, p. 20. Bay State eliminated the deductible for workers compensation as of July 1, 2004. Id.

Mr. Skirtich used a five-year average to normalize the level of self-insured costs for ratemaking purposes, and adjusted the per books amounts for General and Auto Liability claims to the five year average. Exh. BSG/JES-1, p. 20. The resulting adjustment for these insurance categories was an increase of $351,374 in General Liability and a reduction of $12,959 in Auto Liability. Exh. BSG/JES-1, p. 20. Because of the elimination of the workers compensation deductible, Mr. Skirtich eliminated the associated book expense, for a reduction of $258,394 in that area. Exh. BSG/JES-1, p. 20. The combined effect of these adjustments was an increase in O&M expense of $80,021. Exh. BSG/JES-1, pp. 20-21; Exh. BSG/JES-1, at Sch. JES-6, p. 6.

No party has contested Bay State's self insured claims adjustment.

6. Adjustment to Return Gain on Sale of Property

The Department has a long-standing policy requiring the return to ratepayers of gains on the sale of property if the property in question was previously recorded above the line in the utility's rate base. Boston Gas Company, D.P.U. 96-50 (Phase 1), at 111. Since Bay State's last base rate proceeding, Bay State sold utility property that resulted in a gain in four instances: the sale of water heaters in 1995, the sale of the Westborough headquarters in 1997, the sale of LNG trailers in 2001, the sale of propane assets in 2001. The resulting gains on these sales netted $2,040,984, which Bay State proposes to amortize over five years, consistent with its proposed PBR period. Exh. BSG/JES-1, pp. 21-22; Exh. BSG/JES-1, at Sch. JES-6, p. 7; Exh. AG-3-42; Exh. AG-3-43; Exh. AG-3-44; Exh. AG-3-45.

a. Response to Attorney General

i. Calculation of Net Gain - Westborough

The Attorney General states that the Company sold the Westborough building for gross proceeds of $11,409,654 and net proceeds of $10,145,273. AG Br., at 38. [32] The Attorney General contends that the Company incorrectly calculated the amount of net sale gains that should flow to ratepayers because it did not itemize the cost of the transaction. AG Br., at. 38-39. The Attorney General asserts, therefore, that these costs were imprudent and should be disallowed. Bay State disagrees.

[32] In fact, the P&S agreement states that the sale price was $10,800,000. Exh. RR-AG-49, Tabs 1, 2. The $11,409,654 is the original cost as of the date of the sale. AG Br., at 38, n.19.

The closing costs are in the record and are reasonable. RR-AG-49, Tabs 1, 2. The agreed purchase price of $10,800,000 is clearly stated in the purchase agreement, as is the net purchase price of $10,524,000. RR-AG-49, Tab 1, para. 2.1; Tab 2, Items 1, 2. The Closing Costs and Credits are also detailed in the purchase agreement. RR-AG-49, Tab 1, para. 9.3. A summary of expenses based on RR-AG-49, Tab 2 and the nature of the transaction is as follows:

a.	Title Policy Premium	$ 2,631
b.	Transfer Tax (1/2)	$ 47,989
c.	Recording Fees (Est.)	$ 200
d.	Title Examination Fees	$ 1,366
e.	Escrow Fees	$ 250
f.	Broker's Fees	$226,290
g.	Conditions Subsequent (paving)	$276,000
h.	Attorneys Fees[33]	$100,000

These closing costs total $378,727.18, which when deducted from the $10,524,000 result in net proceeds of $10,145,273. RR-AG-49. Bay State's allocation was therefore proper and the Attorney General's proposed adjustment should be dismissed. [34]

33 Given the size of the transaction, it is reasonable to assume that $100,000 in attorney and other professional fees (appraisals) were obtained and account for the difference. Bay State's workpapers demonstrate this was the case. Exh. RR-AG-49.

34 The Attorney General asserts in a footnote that the Department should disallow all the Westborough lease expenses from operating expense "for the same reasons as it includes all of the gains of sale" of the headquarters. AG Br., at 39 n.21. The statement is illogical because Bay State's headquarters lease expense is a normal on-going expense appropriate for inclusion in the revenue requirement at its current level, which was demonstrated to be reasonable.

ii. Westborough Building - Allocation to Affiliates

The Attorney General complains that the net gain was improperly reduced by $141,835 because of required allocations to affiliates. AG Br., at 38. The AG also contends that the Company has not provided the Department and parties with floor plans or the breakdown of square footage attributable to utility versus non-utility operations, separated by sublessee to substantiate that affiliate use of the premises entitles the affiliate to pro-rated gains from the sale. AG Br., at 39.

The Attorney General is incorrect. Bay State has submitted floor plans as part of this proceeding, including a legend of common area and area to be subleased and rented space. Exh. AG-3-41, subpart 4. The Company provided a breakdown of square feet, including common space and rentable space. Exh. AG-3-28, subpart 2, p. 5. All common costs and revenues are allocated to affiliates. Exh. AG-1-27 (illustrates the 16.4% that was used in assigning the gain to Northern), and this allocation was proper. Since Northern's customers supported the use of the building through their payments, a reasonable portion of the gain on the sale should be attributed for their benefit.

iii. Response to Attorney General - Cost Benefit Analysis

The Attorney General argues that the Company failed to conduct a proper cost/benefit analysis comparing the economic advantages or retaining the property or implementing a sale/leaseback agreement and instead of a one-year analysis, the Company should have conducted a 25-year analysis. AG Br., at 40. The Attorney General asserts that the Company has failed to demonstrate that its decision to engage in the sale/leaseback was correct. AG Br., at 40. Bay State disagrees.

Bay State testified that it used its business judgment based on all available information at the time to conclude that it was reasonable to sell and lease back the Westborough facilities, releasing unneeded property and freeing capital for infrastructure repair, replacement and expansion. Tr., at 1567-68. Bay State received a gain on the sale, which has been flowed back to the benefit of ratepayers, reducing the revenue requirement for ratemaking purposes. Exh. BSG/JES-1, Sch. JES-6, p. 7. There was no ratepayer detriment from this course of action, only ratepayer benefit. Bay State's cost/benefit analysis, conducted at the time, demonstrated the decision was prudent. The Attorney General's recommendation that some other analysis should have been employed is proffered through hindsight. The Attorney General can point to nothing that indicates that the decision was not proper for the Company or its ratepayers. The adjustment should be denied.

iv. Sale of Propane Properties

The Attorney General argues that the Company has incorrectly calculated the share of gains by starting the calculation using net proceeds instead of gross proceeds. AG Br., at 41. The Attorney General states the Company should have included sales prices and the cost of the sale in evidence. AG Br., at 41. The Attorney General faults Bay State for applying its management judgment in lieu of a formal cost-benefit analysis. AG Br., at 41-42.

The Attorney General's questioning of this transfer is without merit. First, Bay State was aware its propane properties were of transferred for operational reasons gas supply. Exh. AG-3-

44. Accordingly, Bay State competitively bid the sale of the facilities by placing a public RFP. No third-party bids were received. Exh. AG-3-44. The entity that purchased the facilities EnergyUSA, was at the time affiliated with NiSource but no longer is. The Attorney General's claim that this sale and transfer is not at arms length is undermined by the fact that Bay State first put the properties out to bid, and second, that the purchaser was not an affiliate at the time of purchase.

Moreover, while Bay State duly credited the gains on the sale to the entities that supported the assets (Bay State and Northern), the Attorney General seeks to reallocate those gains. The fact is that the facilities were supported by Northern's ratepayers as well as Bay State's and a portion of the facility was in Northern's base rates. The Attorney General's recommendation to reverse the allocation for ratemaking purposes and assign 100% of the gain to Massachusetts customers is mathematically non-sensical. Bay State should not allocate more gain or loss to its Massachusetts customers than the percentage borne by those customers in rates. Each of the Attorney General's recommendations are without merit and should be dismissed.

7. Rate Case Expense Adjustment

The Department includes in base rates a normalized level of rate case expense so that a representative level is included in the cost of service. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 191; Berkshire Gas Company, D.T.E. 01-56, at 77; Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 54; Boston Gas Company, D.P.U. 96-50 (Phase I), at 77; Berkshire Gas Company, D.P.U. 1490, at 33-34 (1983). The Department's long-standing policy determines the appropriate period for recovery of rate case expenses by taking the average of the intervals between the filing dates of a company's last four rate cases (including the present case), rounded to the nearest whole number. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 191. That number is then compared to the test year level to determine the adjustment. Id. at 197. For companies with PBRs, the Department has modified the standard so the normalization period equals the longer of the traditional period or the duration of any price cap proposal.[35] Boston Gas Company, D.P.U. 96-50 (Phase I), at 78.

Utilities are expected to contain rate case expense by, among other things, engaging in a competitive bidding process for legal and consulting services. If they do not so bid, they must justify why they did not. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 192. Invoices for services must be provided to substantiate recovery. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 194.

Bay State competitively bid the services of its depreciation expert, Earl M. Robinson; its PBR expert, Lawrence R. Kaufmann; its expert on rate of return, Paul R. Moul; its expert on cost of service, marginal cost and the Simplified MBA, James L. Harrison; for assistance for substantiating the SIR, R.J. Rudden; and for legal, Nixon Peabody LLP. Exh. BSG/JES-1, p. 23. This accounts for 82% of total estimated rate case expense. Exh. BSG/JES-1, p. 23. The remaining rate case consultants were hired without competitive bids due to their unique

[35] If a company does not yet have a PBR in place, the normalization calculation takes place consistent with precedent. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 191.

familiarity with Bay State's operations, competitive rates and ability to provide the requested services in an efficient and timely manner. Exh. BSG/JES-1, pp. 23-24.

In its initial filing, Bay State estimated the total rate case expense following detailed discussions with the participants in the case and arrived at an expected cost of $1,658,500, which Mr. Skirtich normalized over five years. Exh. BSG/JES-1, p. 25. The resulting increase in O&M expense was expected to be $331,700. Exh. BSG/JES-1, at Sch. JES-6, p. 8. These estimates of rate case expense included a number of studies undertaken to meet the basic inquiries made by the Department on a routine basis in its investigation of base rate increases: building allocations, audits of service quality measures, and justification of reasonableness of affiliate service costs, etc. In addition, in order to ensure costs were monitored and evaluated on a continuing basis, Bay State assigned its project manager for the rate case to monitor on a bi-weekly basis the costs as they were being incurred. Every invoice was reviewed and approved by the project manager, whose initials appear thereon. Exh. DTE-15-58. This constant monitoring was an effective way of ensuring that only necessary work was being performed and that the work was being performed to advance the rate case process.

Bay State believes that due to the unanticipated litigation costs associated with presenting and defending the case within a very compressed time period, the sheer size and complexity of this proceeding exceeded all reasonable expectations. Based on a comparison to the Boston Gas Company proceeding, D.T.E. 03-40, where rate case expense was approximately $2.1 million, Bay State faced more discovery and a more complex case for presentation:

Table BSG-2

	Boston Gas (2003)	**Bay State (2005)**
Years since Last Rate Proceeding that Included Rate Base Updates	6.5	13
No. of Binders Comprising Initial Case Filing materials	5 (total)	11 (total)
Dates that Transpired for Discovery as compared to Initial Case Filing Date	1st Set – Day 0 Last Set – Day 65	1st Set – Day 9 Last Set – Day 56
Total IRs Received, Including Post Deadline IRs of Department	1,419	1,607
No. Days Expended Before Delivering Initial Discovery Responses to AG and DTE	23 Days	12 Days
No. of Witnesses	5 internal, 3 expert	4 internal, 5 expert
No. of Full Intervenors Issuing Discovery and Participating in Hearings, in addition to Department Staff	5 (AG, DOER, MASSCAP, MOC, MDFA)	8 (AG, DOER, MOC, MASSCAP, MassPower, USWA, UWUA, KeySpan)
No. Days of Evidentiary Hearings	26	25
Days Spanning Start and End of Evidentiary Hearings	6/26 through 8/11	7/5 through 8/11
No. Pages of Transcripted Hearings	3,652 pages	4,052 pages
No. of Record Requests	248	308

	Boston Gas (2003)	Bay State (2005)
Arising from Hearings		
Total Discovery Responses (not including updates and supplements)	1,667	1,915

It is not unexpected therefore, that as the case progressed, rate case expense was driven upward, in spite of many steps undertaken by Bay State to actively control its escalation: for instance, much of the case was produced and supported in-house by Bay State employees and a significant portion of the case was litigated directly by Bay State's in-house regulatory counsel from NCSC. Nonetheless, in order to meet the demands of the litigation schedule and the volume of discovery requests, Bay State was required to bring additional regulatory assistance from Nixon Peabody to its Westborough office to support the discovery effort and to try to meet the tight deadlines and discovery expectations of both the Department and intervenors.

a. Response to Attorney General

The Attorney General recommends that the Department disallow certain rate case expenses claiming no "ratepayer benefit" was demonstrated and certain services were not put out to bid. AG Br., at p. 84-85. For instance, the Attorney General believes that the expenses associated with Hewitt Associates, R.J. Rudden, Yardley and Associates, Corporate Renaissance, Coler and Colantonio and Bank of America Leasing should be removed from rate case expense. AG Br., at 84-87.

The proposed adjustments amount to a red herring and in many places the Attorney General's argument is illogical. A utility is not required to demonstrate of a "ratepayer benefit" to justify rate case expense under Department precedent nor is it required to present a witness from each consultant employed for the rate case. Reasonable rate case expense is recoverable as part of the constitutional protection against confiscation of a utility's private property (its expenses and revenues). Both ratepayers and shareholders benefit from a just and reasonable ratesetting process and the normalization of rate case expense demonstrates a sharing of the costs between shareholders and ratepayers. As stated above, under the Department's long-standing rate case recovery standards, a utility must normalize rate case expense and demonstrate it has contained costs (generally by competitive bidding). Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 192 and the cases cited therein; Boston Gas Company, D.P.U. 96-50 (Phase I), at 79.

Contrary to the Attorney General's assertions, Hewitt's work for Bay State on the rate case was not subsumed in its broader contract with NiSource.[36] AG Br., at 85. Bay State separately contracted with Hewitt to develop with Mr. Barkauskas the many comparative analyses the Department requires to demonstrate reasonableness of union payroll, non-union and executive compensation, benefits, total compensation and incentive compensation. Exh. DTE-15-56; Exh. DTE-15-58; Exh. BSG/SAB-1, pp. 44-45; Exh. BSG/SAB-1, Sch. SAB-9. The schedules contained in Mr. Barkauskas' prefiled direct testimony were created for the rate case only. NiSource asked Hewitt to conduct a separate wage and compensation analysis during 2004

[36] NiSource's long-standing relationship with Hewitt and Hewitt's intimate knowledge of NiSource and its subsidiaries' human resources issues substitutes for the competitive bidding the Attorney General says was lacking. Exh. AG-12-06 (Confidential). Any other consultant would have been required at the outset to expend extensive resources to develop the necessary background information on NiSource's compensation structure in order to produce the comparative compensation analyses required by the Department. Bay State's use of Hewitt, therefore resulted in rate case cost containment.

that was employed system-wide and was not based on the Department's regulatory analysis. NiSource also used Hewitt to advise it on corporate actuarial pension and PBOP issues. Exh. AG-4-1; Exh. AG-4-11. These services were not included in rate case expense. Bay State also benefited from the association as Hewitt was asked by Mr. Barkauskas to confirm his analysis of the volatility of pension/PBOP expense to justify the Department's standard to move such obligations from base rates to the PEF mechanism. The analyses contained in Mr. Barkauskas' prefiled direct testimony and discovery support provided were necessary to demonstrate reasonableness of compensation and the volatility of pension and post retirement benefit obligations. Exh. BSG/SAB-1, pp. 46-48; Table SAB-1, at p. 48; Exh. BSG/SAB-1 at Sch.. Bay State provided the analysis with Hewitt's assistance, and the cost is justifiably recoverable as rate case expense.[37]

The RJ Rudden services were competitively bid during the test year, and as Mr. Bryant explained, Bay State felt it was necessary, given that the SIR program was a change in direction for Bay State, to have an outside expert evaluate its program. Tr., at 1054-57. Since the SIR proposal would be part of the rate filing, the Rudden report was a reasonable expenses to incur as it would aid the Department in its ultimate determination of the reasonableness of this capital replacement program. The report was produced in discovery and was the subject of extensive review in this proceeding. Exh. DTE-2-16. Any recommendation to remove this expense from rate case expense is improper.

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[37] While Bay State has no obligation to produce a Hewitt witness in order to recover these expenses, it would state presenting such a witness was unnecessary: Mr. Barkauskas proved to be a knowledgeable and competent witness on all compensation issues.

The Yardley and Associates expenses are equally valid. Exh. DTE-15-58; Exh. AG-3-20. Mr. Ferro is a time-constrained manager for Northern and Bay State as his supervisory roles include regulatory proceedings and oversight of all cost of gas adjustments, pricing issues and tariff matters in Massachusetts, Maine and New Hampshire. Exh. BSG/JAF-1, p. 1. Daniel Yardley is an experienced utility and regulatory consultant who has worked with Mr. Ferro and Bay State for many years on issues ranging from capacity assignment and market issues to tariff and rate design. His extensive knowledge was of invaluable assistance to assist Mr. Ferro in the preparation of his testimony and discovery. Exh. DTE-56. These costs helped in the administration and presentation of the case, and should be allowed.

With regard to the building allocation confirmed by Coler and Colantonio the allocation of costs and method of cost sharing under the management agreement between Bay State and Northern was directly at issue in Bay State's previous rate proceeding and Bay State believe it had an obligation to present a building allocation study. Bay State Gas Company, D.P.U. 92-111 (1992). The building allocation study was required to support Bay State's burden of proof on as to whether the appropriate amount of building space was allocated to affiliates in the cost of service. Bay State agrees with the Attorney General's proposal to allocate a portion of this reasonably incurred expense to Northern. RR-DTE-144. With that adjustment, the Department should find that the Coler and Colantonio evaluation was necessary to a relevant issue in this case, and the list of that evaluation should be allowed.[38]

[38] Compare AG Br., at 86-87. Once again the Attorney General has requested information that drives costs up for no apparent benefit. This expense may have been included in the initial proposal, but determined to be
(Footnote continued on next page)

With regard to the expenses incurred for the service quality performance audit conducted by Corporate Renaissance, Bay State determined this audit was necessary to confirm its compliance with the Department's service quality standards as it sought approval of its first PBR. In recent rate cases and merger cases, the Attorney General and the Unions have challenged utility compliance with those standards and called for an investigation into the measurement and metrics standards. Engaging a firm for this particular audit reduced rate case expense by removing a issue of contention in this proceeding (i.e., whether Bay State was correctly measuring its standards) as Bay State sought Department approval of its first full PBR Plan. Contrary to the Attorney General's assertion, Corporate Renaissance was not engaged to provide services to Bay State for preparing its service quality reports. Exh. DTE-15-56 (contract demonstrates purpose is to support the rate case). The Corporate Rennaissance fees are reasonable and should be included in rate case expense.

With regard to the Attorney General's claim that meals should be unrecoverable,[39] the majority of meals included for rate case expense are weekend and night meals for staff in Westborough, or for experts or outside consultants for hearings in Boston. Cf. AG Br., at 86. First, the Westborough location is a corporate park; there are no restaurants within walking distance. People working long hours to support the rate case must be provided meals on site and if the meals expense is reasonable, it should be allowed. Second, outside consultants normally

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(Footnote continued from previous page)
unnecessary. Since no party has challenged Bay State's building allocations to Northern, electronic map copies have no purpose now either.

[39] The Attorney General claims there should be a demonstrable "ratepayer benefit" to the meals expense. AG Br., at 86. Since no such standard exists, Bay State does not respond to it here.

charge for meals when traveling significant distances overnight. None of these expenses extraordinary, unusual or unreasonable. They all should be allowed.

b. A Bay State Proposal

The rate case expense and the size of the record have clearly caused concern for all parties of this proceeding. Bay State could not reasonable have anticipated that its discovery burden would exceed KeySpan's 2003 rate proceeding. Under the Department's current discovery practice, the breadth of inquiry permitted is inconsistent with the Department's limited statutory period for investigation. While Bay State did not to any significant extent pose objections to the discovery propounded on it on the grounds of burdensomeness or relevance, the amount of discovery requested was clearing at odds with the time allowed to conduct this proceeding. Bay State requests that the Department consider methods to encourage intervenors to issue only those requests that thoughtfully reach material issues. One way would be to limit the total number of sets of information requests that can be issued per party at the outset of hearings and also to limit the number of questions per set, for example, to 20 or 30 (with three subquestions), similar to the requirements of state or federal civil practice. This would serve to reduce the burden on all parties and the Department, increase the speed of response, reduce cost, focus the parties to pertinent issues more quickly and more likely lead to the discovery of material evidence of use to the Department. Bay State would also suggest that the Department permit any party to seek a waiver from the Department for good cause shown (or by stipulation) if that party finds it requires additional discovery in a pertinent area. Bay State at that time could not (and did not) reasonably anticipate its discovery burden would exceed KeySpan's 2003 rate proceeding.

8. Bad Debt Expense – Gas Revenue

a. Introduction

The Department permits a representative level of bad debt expense to be included in rates. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 162, 168.

A company must determine the average of the most recent consecutive three years' net write-offs, as a percentage of the total retail revenues for the corresponding period (the uncollectible ratio). Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 162, 168. Each year is based on the last month of the year if those numbers are representative. Gas companies may recover their allowed bad debt expense through base rates and through the gas adjustment factor. Id., at 163. The Department determines semi-annually, in the GAF proceedings, an allocation factor to apply to the level of bad debt approved in the rate case, in order to account for migration to the competitive market. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 172.

The Department has annualized write-offs in a given year where the last month's net write-offs were unrepresentative. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 162, 168.

b. Gas Revenue Bad Debt

In order to establish bad debt for the purposes of establishing rates, Bay State totaled bad debt for gas revenues for the last three years, including the test year, for net write-offs and firm billed revenues. Exh. BSG/JES-1, p. 26; Exh. BSG/JES-1, at Sch. JES-6 (Corrected), p. 9. Initially, a bad debt ratio of 2.17% was established by dividing total net write-offs by total firm revenues. Id. This number was updated to 2.15% during the course of the proceeding. Exh. DTE-16-3 (Supplemental). Test year firm revenues, once normalized for weather and unbilled revenue adjustments, were multiplied by the bad debt ratio to derive bad debt expense for Gas Service for ratemaking purposes. This equated to $10,305,726 bad debt expense. Exh. BSG/JES-1 at Sch. JES-6, p. 9. The test year level of bad debt of $3,199,694 was subtracted and the pro forma increase of $7,106,032 resulted. Exh. BSG/JES-1, p. 26; Exh. BSG/JES-1, at Sch. JES-6, p. 9.

i. Response to the Attorney General

The Attorney General states that although the Company calculated the base rate bad debt allowance in a manner consistent with current Department precedent, the component related to the CGA does not comply with current precedent and, therefore, the Department should reject the CGA component. AG Br., at 68-72. The methodology used by the Company is consistent with the Department's decisions in the recent Fitchburg Gas and Electric Light Company and Boston Gas Company rate cases. Fitchburg Gas and Elec. Light Company, D.T.E. 02-24/25 (2002), p. 172 ; Boston Gas Company, D.P.U. 03-40 (2003), p. 267. The Attorney General agrees with Bay State's rate design proposal to collect a portion of the bad debt allowance through the proposed base rates and the gas-related portion through the CGA. AG Br., at 69. This method was first approved in the settlement in D.T.E. 97-97 and in D.T.E. 96-50 (Phase I).

Bay State, KeySpan and the Attorney General appear to be in agreement on this issue. Exh. KEDNE-2, p. 2). Bay State requests that the Department affirm Bay State's treatment of bad debt as set forth in this proceeding and consistent with Bay State's prior practice. The same reasons exist today as in the late 1990s to justify why Bay State and other Massachusetts LDCs moved bad debt expense associated with gas cost collections from base rates into the CGAC.: to capture the changing conditions with respect to a gas utility's bad debt expense associated with the volatility of commodity gas costs and the movement of customers from firm sales to firm transportation service. Thus, a mechanism was established to recover the actual bad debt expense associated with gas costs going forward, an expense that is affected both by the level of bad debt expense and the proportion of that expense associated with gas cost.

c. Energy Products & Services Bad Debt

Bay State supports additional services through rates. These services, such as Guardian Care service business activities and the Water Heater rental business, provide ratepayer benefits including a significant contribution to O&M revenues. Exh. BSG/SHB-1, p. 55, Exh. BSG/JES-1, p. 27. In order to properly reflect bad debt expense associated with EP&S activities, Bay State used the Department's standard for gas utility service in calculating the appropriate level of bad debt for ratemaking purposes. Exh. BSG/JES-1, p. 27; Exh. BSG/JES-1, at Sch. JES-6, p. 10.

The total allowable net bad debt expense to be included in rates following the calculation is an increase of $246,232. Id.

i. Response to the Attorney General

The Attorney General proposes that the bad debt level for EP&S should be reduced to test year levels. AG Br., p. 74. The Company followed Department precedent in calculating bad debt and is giving credit for net profit. Exh. BSG/SHB-1, pp. 53-54. The bad debt expense increase for the EP&S businesses is a legitimate cost of those businesses, and the Attorney General has provided no basis for its removal, except his observation that the bad debt rate for the EP&S program is higher than the bad debt rate for the regulated operations of the Company. While he implies this may not be the result of "prudent actions" by the Company, he provides no support for that statement. Id. Moreover, the assignment of partial customer payments first to regulated sales, would result in higher uncollectible accounts expense for the unregulated EP&S business. See M.G.L. c. 164, sec. 124B. The Attorney General has proposed that the Department increase revenues for fee increases, which is inconsistent with this proposal. Because of the inconsistency, both proposals to change Bay State's recovery of EP&S costs, should be rejected.

9. NCSC Expense Adjustment

Under Department precedent, in order to qualify for inclusion in rates, payments made by a utility to an affiliate must be: (1) for activities that specifically benefit the regulated utility and do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) be allocated to the utility by a formula that is both cost-effective and non-discriminatory for services specifically provided to the utility by the affiliate and for general services which may be allocated by the affiliate to all operating affiliates. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 180; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). The level of all affiliate charges must be justified and be reasonable with proper substantiation. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 181-82.

As discussed infra, NCSC provides, on a system-wide basis, professional, managerial and technical services that include accounting, payroll, auditing, employee benefits, planning, risk management, tax, legal, environmental, financial, data processing, telecommunications and general advisory services. Exh. BSG/JES-1, p. 28. NCSC provides these services to Bay State pursuant to an SEC-approved agreement and NCSC follows the SEC Uniform System of Accounts for Service Companies and Subsidiary Companies. NCSC uses a job order system to collect costs that are billable to Bay State. Exh. BSG/JES-1, pp. 29-30. While allocation methods are used when services are rendered by NCSC to more than one affiliate, direct billing and direct charging is always deemed preferable where practicable. Exh. BSG/JES-1, pp. 29-30. NCSC bills through contract and convenience billing, and the monthly invoice rendered to Bay State details the functional area or cost center served by NCSC, and by job order the cost of services provided. Exh. BSG/JES-1 at 29. Consistent with federal law and applicable SEC rules and regulations, NCSC provides its services to all affiliates at its cost. It does not mark-up any bills to affiliates. Exh. BSG/SHB-1, pp. 19-20; Exh. BSG/JES-1, p. 28.

For ratemaking purposes, Bay State removed charitable contributions from the NCSC bills for the test year, reducing the test year NCSC expense by $8,735. Exh. BSG/JES-1, p. 31; Exh. BSG/JES-1, at Sch. JES-6, p. 11. In addition, Bay State adjusted the test year NCSC bill related to payroll to reflect known and measurable increases in payroll, wages and benefits. Exh. BSG/JES-1, p. 31. In particular, payroll was adjusted to reflect an annualization of the March 1, 2004 merit increase as well as the merit increase posted March 1, 2005 and the 2006 increase. The increases total $454,871. Exh. BSG/JES-1, p. 31; Exh. BSG/JES-1 at Sch. JES-6, p. 11. Medical and dental insurance costs were increased similar to the adjustment made for Bay State employees, by $274,566. Exh. BSG/JES-1, p. 31; Exh. BSG/JES-1 at Sch. JES-6, p. 11. Payroll taxes were increased to reflect changes in FICA, Social Security and Medicare, totaling $27,421. Exh. BSG/JES-1, pp. 31-32; Exh. BSG/JES-1, at Sch. JES-6, p. 11. The net change was an increase of $748,122. Exh. BSG/JES-1, p. 32; Exh. BSG/JES-1, at Sch. JES-6, p. 11.

a. Response to Attorney General

The Attorney General challenges the increases to medical and dental insurance premiums for NCSC as not known and measurable. AG Br., at 78. The Attorney General argues, completely without citation, that NCSC employees "reside mostly in Indiana" and have different increases than Bay State employees. AG Br., at 78-79. He argues, that there are different rates of increase for Bay State and NCSC health care costs. AG Br., at 79.[40] He also argues that there

[40] The argument made by the Attorney General is that since there is an apparent disparity in the cost of labor service company increase (Bay State is asserted to be higher), there must be a disparity in health care increases between NCSC and Bay State. AG Br., at 79. The argument fails as Bay State's 2.21% salary increase is made of a 2% salary increase for exempt employees. The NCSC salary increase of 1.9% is predominantly for exempt employees as well.

are "different mixtures of coverage" that would cause the increases in various insurance plans to be different. AG Br., at 79.

Bay State's proposed medical benefits insurance adjustment to cover its expected increased expenses under the Bay State-NCSC Corporate Services Agreement is supported by the testimony and exhibits of Mr. Barkauskas. Exh. BSG/SAB-1 pp. 2-373; Exh. BSG/JES-1, Schedules JES-6, pp. 4, 41-43. The NCSC employees that provide services for Bay State do not "mostly" reside in Indiana, but reside in Massachusetts, Ohio and Pennsylvania in addition to Indiana. Mr. Barkauskas, a professional in the human resources area, testified that the increases between the medical costs for NCSC service locations and the operating companies are sufficiently similar to establish a single percentage increases. Bay State's proposed increase in the revenue requirement to reflect reasonable and known increases in NCSC medical benefits is appropriate and should be allowed. Exh. BSG/SAB-1 pp. 2-371. The Attorney General has presented no evidence to call in to question Mr. Barkauskas' professional determination of the expected rate of cost increases for the classes of medical coverage applicable to NCSC. Bay State's requested adjustment is known, reflects an actively contained medical benefit cost, is reasonably calculated, and should be adopted.

b. Response to UWUA

UWUA claims that the allocations to Bay State of NCSC executive compensation is excessive, and has increased dramatically since 2001. UWUA Br., at 62-64. The amounts for executive compensation have been within a reasonable range since 2002 and reflect the contribution those individuals made directly to Bay State as indicated by their time sheets. As

Mr. Bryant testified, the officers of NiSource executives manage thousands of employees in 11 states. NiSource is the third largest natural gas pipeline and distribution company in the United States. Along with Bay State, the NiSource system serves 3.2 million retail customers and operates gas pipeline systems running across the United States and into New England. The offices of NiSource are paid salaries commensurate with their counterparts at other large gas companies in the industry. As Mr. Barkauskas testified, the compensation packages for the NiSource offices are necessary to attract and retain top executives. Tr., at 2305-08. All executive and officer compensation is approved by the NiSource Board of Directors following study, review and recommendations made by the Compensation Committee of the Board.

The method of allocating officer time to affiliates is either based upon time (direct charging) or an allocation methodology approved by the SEC for use by NCSC in charging its affiliated companies at cost. For the test year, which is the only year that has any bearing on the forward-looking rates to be set in this proceeding, all allocation methodologies were reviewed and approved for use by the SEC.[41]

For all these reasons, the amounts charged to Bay State by NCSC for the compensation of NiSource's offices are reasonable in amount and allocation. UWUA's proposed disallowance is without merit and should be rejected.

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[41] UWUA mentions the smaller amount of officers executive compensation allocated to Bay State in 2001 compared to more recent years, but nevertheless, what happened in 2001 is irrelevant to setting rates based on a 2004 test year, so long as the allocated amount reflects a legitimate and reasonably derived expense. The NiSource merger with Columbia occurred in 2000 along with the creation of NCSC at the same time, which may have effected the lower level of compensation allocated in 2001.

10. **Adjustment to Remove Charitable Contributions**

The Department excludes charitable contributions from the cost of service absent evidence that such contributions are reasonable and provide direct benefits to ratepayers. Commonwealth Electric Company, D.P.U. 88-135/151, at 45 (1989); Boston Gas Company, D.P.U. 88-67 (Phase I), at 118-27 (1988). Bay State determined to absorb the cost of its charitable contributions in the test year, and accordingly removed $147,271 from Bay State's revenue requirements. Exh. BSG/JES-1, p. 32.

11. **Amortization of Deferred Farm Discount Credits**

The Farm Discount was authorized by the Electric Restructuring Act and applies to gas customers engaged in farming and agriculture and provides for 10 percent reduction in the rates to which such customers would otherwise be subject. St. 1997, c. 164, sec. 315; see Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 203. Certain companies, such as Bay State, were allowed to defer the farm credit revenue for consideration in the next rate case. Id., at 203-04. Accordingly, the amount of farm discounts provided to eligible customers from 2002 through the end of the test year was $76,600. Exh. BSG/JES-1, p. 33; Exh. BSG/JES-1, at Sch. JES-6, p. 13. Bay State proposes to amortize this over a five-year period for a pro forma adjustment to Bay State's test year revenue requirement of $15,320. Id.

12. **Postage Adjustment**

On April 8, 2005, the United States Postal Service announced its intent to seek a 5.41% increase in rates by early 2006. Exh. BSG/JES-1, p. 34. Accordingly, Bay State proposed a

$67,947 increase in postage cost related to the proposed increase. Id.; Exh. BSG/JES-1, at Sch. JES-6, p. 14. Bay State presented evidence that the United States Postal Service is presenting its case for the increase before the United States Postal Rate Commission, and that a decision is expected before the end of the proceeding, and no later than the midpoint of the rate year.

No party has contested Bay State's proposal to recover the costs associated with the 2005 postage increase.

13. Adjustment for Research and Development Costs Related to GTI Activity - Withdrawn

In its initial filing, Bay State proposed to recover $310,000 in its rate year revenue requirement for to support for the Gas Technology Institute's Operations Technology Development and Environmental Issues Consortium. Exh. BSG/DGC-1, p. 4; Exh. BSG/JES-1, p. 34; Exh. BSG/JES-1, at Sch. JES-6, p. 15. However, Bay State determined, while the case was pending that, given the complexity of issues inherent in its request, it would withdraw this request. Tr., at 1049; RR-DTE-18. Bay State submits this issue may be more appropriate for consideration in an industry-wide investigation into the appropriate level of research and development contributions made by natural gas utilities and their customers.

No party contested the Company's withdrawal of this issue from the proceedings.

14. Adjustment for Increases in Itron Lease Payment

Bay State purchased new Itron Encoding and Receiving Transmitters ("ERT") and sold and leased back a block of units with a cost of approximately $2.4 million in December 2004. Exh. BSG/JES-1, pp. 34-35; Exh. BSG/JES-1, at Sch. JES-6, p. 16. In order to annualize the lease expense level, Mr. Skirtich adjusted O&M expense to reflect the annual lease payments, resulting in a pro forma adjustment of $310,104. Exh. BSG/JES-1, p. 35; Exh. BSG/JES-1, at Sch. JES-6, p. 16.[42]

No party has contested the Company's adjustment for an increase in the Itron lease payment.

15. Metscan Meter Reading Lease Payment

Bay State has removed virtually all of its Metscan meter reading devices from service because they were no longer performing as required. Exh. BSG/SHB-1, p. 45. As discussed above, some of these devices had been sold and leased back to Bay State in December 2004. Exh. BSG/JES-1, p. 35. Since at the time the case was filed, Bay State was actively negotiating with the leaseholder, Fleet Capital, for a buy-out of the remaining lease in order to eliminate the monthly lease expense from Bay State's on-going O&M. Bay State eliminated $2,919,051 of lease payment costs from Bay State's test year O&M expense that was related to long-term leases of Metscan meter reading devises. Exh. BSG/JES-1, pp. 35-36; Exh. BSG/JES-1, at Sch. JES-6, p. 17. No party has contested Bay State's conditional removal of the lease payments from the revenue requirement, pending the Department's approval of the amortization of the buy-out payment for the lease.

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[42] Mr. Skirtich explained that these units were not included in the Company's rate base because the sale was completed before the end of the test year, and depreciation associated with the units for 2004 was eliminated through an annualization adjustment of depreciation. See Exh. BSG/JES-1, p. 35.

16. CGA and LDAC Recoverable Costs

Certain costs incurred by utilities are recoverable through a gas company's cost of gas adjustment ("CGA") and/or Local Distribution Adjustment Clause ("LDAC"). Such costs include demand side management costs, environmental remediation costs and bad debts related to gas costs. As these costs are recovered through revenues, a corresponding cost is recognized in operating and maintenance expense ("O&M expense"). The costs are excluded from O&M expense, as well as revenue, to reflect the proper level of O&M expense for base rate recovery. Exh. BSG/JES-1, p. 36, Exh. BSG/JES-1 at Sch. JES-6, p. 18. No party has questioned this adjustment.

17. Inflation Adjustment

The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 184. The utility must demonstrate that it has implemented cost containment measures in order to recover an inflation adjustment. Boston Gas Company, D.P.U. 96-50 (Phase I), at 113. If an O&M expense was adjusted or disallowed for ratemaking purposes, that expense is also removed in its entirety from the inflation allowance. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 184; Boston Gas Company, D.P.U. 9\88-67 (Phase One), at 141 (1988); Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987).

a. Response to the Attorney General

The Attorney General argues that the Company failed to remove certain capital related costs (i.e., depreciation, interest, income taxes and property taxes) billed from its affiliates from residual O&M costs in the inflation amount. AG Br., at 80-81. However, costs are subject to inflation and squarely fall within the ambit of the costs for which the inflation adjustment was designed. The Attorney General's attempt to characterize these costs as "capital" is not correct. These costs are not "fixed," and together these expenses are subject to inflationary pressure and are not individually adjusted in any other area in this filing. Accordingly, they are appropriately included in the inflation adjustment.

D. Amortizations

1. Metscan Amortization

In the late 1980's Bay State evaluated a number of automated meter reading technologies for consideration to replace the practice of manual meter reading. Tr., at 979. The need arose because of the high economic cost and relative inefficiency of having a skilled company employee walk a meter-reading route, approach each residence or business and then read each meter's usage, in order to manually transcribe the usage into a log, for another employee to later translate and input the transcription to the CIS and billing units of the Company. See Exh. BSG/SHB-1, p. 46; Tr., at 982. The automated technologies reduced a number of these steps and to permitted a utility to obtain more accurate and more frequent meter reads. In part as a result of improved technology, the Department began to require actual meter readings every month.

The two technologies that were evaluated in detail at that time by Bay State were the Metscan product, in issue in this proceeding, and the Enscan product, today known as Itron radio-based technology. Tr., at 979-80. In 1987, Bay State field tested Metscan. Exh. BSG/SHB-1, p. 4. By the early 1990s, Bay State decided that Metscan was the superior product because it was able to provide a greater amount of meter reading information due to its telephone-based technology. Tr., at 980. In the late 1980s, Bay State agreed to be a beta test site for Metscan meters and later to establish a pilot program for the use of the Metscan telephone-based technology. The Metscan technology is a device that is attached to a gas meter and translates the mechanical motion of the meter dials into measured pulses that are stored in the device for later communication over phone lines to Bay State's CIS. Exh. BSG/SHB-1, p. 45; Tr., at 138-39.

Full scale deployment of the Metscan devices commenced after the pilot program was completed. Exh. BSG/SHB-1, p. 46; Tr., at 139; RR-DTE-49 (Supplemental) Ultimately, approximately 270,000 meters were installed on residential and commercial accounts throughout Bay State's service territories. Tr., at 981. The device was particularly useful for commercial accounts because it was capable of daily meter reading. See, Tr., at 983-984.

The Metscan technology relies on a battery, and Bay State determined that a battery life of six or seven years was reasonable, but for a meter without a monthly meter read, the battery life expectation was longer. Tr., at 981-82, 989. Nevertheless, the seven years coincided with the Department's seven-year meter change-out requirement and the requirement of periodic meter testing. Exh. BSG/DGC-2, pp. 1-2; Tr., at 981-82. From the commencement of deployment, the Company capitalized all the installed Metscan meter devices, carried them on its books as plant in service and began depreciating them as a class of assets. Tr., at 986. The Metscan meter devices were phased into service commencing in the late 1980s, and phased out of service commencing in 2001. Exh. BSG/SHB-1, pp 46, 48.. During their tenure, the devices made hundreds of thousands of automatic meter readings, operating precisely as intended. Exh. BSG/SHB-1, p. 47.

In 1998, the Company entered into a sale/leaseback arrangement for a number of the devices with Fleet Capital Leasing. Exh. DTE-1-20; Tr., at 985-86. The lease term ran through 2008. Id. As the ownership of devices was transferred to Fleet, Bay State retired the Metscan assets from its books. Tr., at 990. Bay State has paid the lease expense from its operating expenses since 1998.

Problems with the Metscan technology emerged in the late 1990's, as the units that had been installed in phased deployment were evaluated as the phased 7-year meter exchange commenced. Exh. BSG/SHB-1, pp. 45-46; Tr., at 140. The failure diagnosis was that Metscan devices attached to outside meter units were susceptible to the elements and as a result, could and cease communicating usage data to the Company. Exh. BSG/SHB-1. This caused Bay State to commence retiring many of the Metscan devices. Tr., at 991.

After observing the device failure pattern for over 2 years, the Company engaged in another complete analysis of its options in 2000 and 2001. Exh. AG-3-32(B); Tr., at 983. By this time, it was clear that the technology was no longer productive. RR-DTE-48.

Bay State began to look for an alternative and turned to the well-established Itron technology that had come to dominate the marketplace. Tr., at 983. The changeout commenced and Bay State purchased Itron units to replace the Metscan meters remaining in the field. Since 2001, Bay State has been phasing the Metscan meter devices out of operation and replacing the meter fleet with Itron units.

Two thousand four hundred and sixty-five (2,465) Metscan equipped meters remained in use at the end of the test year, and the remaining units in place are there to serve the larger daily metered customers. Tr., at 146-47; Exh. AG-3-31;

No party contested the amortization of the Metscan lease buy-out payments on brief. Moreover no party but UWUA claims Bay State was imprudent in purchasing and deploying the Metscan devices. Bay State has amply demonstrated that the deployment of Metscan devices was reasonable and prudent, based on the information available to the Company at the time.

In its initial filing, Bay State included in its revenue requirement $13,216,748, amortized over five (5) years to recover the net present value of a long-term operating lease and the net book value of the Metscan plant that remained on the Company's books and records as of December 31, 2004. Exh. BSG/JES-1, p. 41; Exh. BSG/JES-1, at Sch. JES-8, p. 3. The net book value of the devices as of December 31, 2004 is $3,121,366. Id. The value of the long-term lease is $10,095,382. Exh. BSG/JES-1, pp. 41-42; Exh. BSG/JES-1, at Sch. JES-8, p. 3. The annual amortization is $2,643,350. Id. Bay State seeks the Department's approval of this amortization.

a. Amortization of Remaining Investment

The Department's standard precedent requires that for expenditures to be included in rate base, the expenditures must be prudently incurred based on what could reasonably have been known at the time, and the resulting plant must be used and useful in providing service to ratepayers. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 12 (1998); Boston Gas Company, D.P.U. 93-60, at 24 (1993); Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986).

The evidence demonstrates that Bay State's Metscan devices were a prudent investment when purchased based on what was known at the time, and were used to benefit customers. The Department recognizes that where an initial investment was prudently incurred but is no longer used and useful, the utility should remove the undepreciated amount of the investment from rate base and amortize it over a reasonable period of time.[43] Under Department precedent, the appropriate recovery of the remaining balance is by amortization of the undepreciated, prudently-incurred plant without carrying costs or any return. This treatment is consistent with Bay State's request in this proceeding: to permit Bay State a return of, but not on, the Metscan balances. Wylde Wood Water Works, Inc., D.P.U. 86-93 (1987); Western Mass. Electric Company, D.P.U. 85-270 (1986); Fitchburg Gas and Electric Light Company, D.P.U. 19084 (1977); Fitchburg Gas and Electric Light Company v. Department of Pub. Utilities, 371 Mass.

[43] Bay State was unable to identify a precedent for investments made and retired between rate cases which is pertinent for Bay State here since this, and its prior rate case, are 13 years apart. However, there is no policy basis that would treat investments made between rate cases differently.

881, 886-87 (1977); Fitchburg Gas and Electric Light Company, D.P.U. 18296/18297 (1975); Fitchburg Gas and Electric Light Company, D.P.U. 18031-A (1975); Fitchburg Gas and Electric Light Company, D.P.U. 18031 (1974).

The Department has in the past considered such early retirements to be extraordinary, especially when the plant in issue can be considered redundant to newly installed plant. In such cases, the Department has taken the affected plant out of rate base and has permitted the unamortized balance to be expensed over an appropriate number of years. The Department has approved in the context of abandoned plant, the same amortization treatment that Bay State now seeks relative to the Metscan undepreciated balance. NYNEX, D.P.U. 94-50 (1995)[44]; New England Tel. & Tel. Company, D.P.U. 86-33-G (1999).[45]

b. Amortization of Metscan Lease Buy-Out

The Metscan lease was an operating lease and the buy-out of the Metscan lease caused by the terms of the lease agreement with Fleet is a significant non-recurring expense. Tr., at 149; Exh. DTE-1-20 (Revised). The Department deems three classes of expenses recoverable through rates: (1) annually recurring expenses; (2) periodically recurring expenses; and (3) extraordinary non-recurring expenses. Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 32-33. Non-recurring expenses are normally ineligible for inclusion in the cost of service, unless it

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[44] In this case, copper cable was used only in a limited manner to provide service, and had been mostly depreciated; disallowance of "this type of plant may discourage utilities from making the optimal, but necessarily 'lumpy,' investment of new plant." D.P.U. 94-50, at 300.

[45] This case involved the recovery of retired Centrex plant. D.P.U. 88-33-G, at 37-44. Over the Attorney General's objections, the Department removed the plant from rate base and amortized the undepreciated plan over three years.

is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. Id.

Department precedent holds that extraordinary, non-recurring expenses may be recovered over time in order to insulate the utility from business risk resulting from large, unanticipated expenditures. The Department's treatment of extraordinary expense, which permits an amortization over a reasonable period of time (and which permits the amortized amount to be included in O&M for the purpose of calculating the Company's working capital adjustment), but which does not permit a return on the unamortized balance, is viewed as an appropriate and reasonable sharing of the risk of large, unanticipated expenditures between ratepayers and stockholders. Boston Edison Company, D.P.U. 1720, at 89 (1984).[46]

c. Response to Attorney General

The Attorney General claims the Metscan costs are associated with a "redundant, unused asset that is not in service and therefore no providing any benefit to ratepayers." AG Br., at 87. The Attorney General claims these assets are inappropriate for inclusion in rate base because they are not used and useful. AG Br., at 87-88.

The Metscan meter devices are not an asset that Bay State is seeking to place in rate base, they are a single class of assets that were phased into service and were phased out of service.

[46] Under this precedent, the balance of abandoned Seabrook II costs were amortized (Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414); the expenses associated with gas supply contract termination negotiations were amortized (Boston Gas Company, D.P.U. 93-60 (1993)); employee severance payments were amortized (Berkshire Gas Company, D.P.U. 92-210 (1993)); along with environmental response costs (for an electric utility) (Nantucket Electric Company, D.P.U. 91-103 (1991)); Hurricane Gloria storm expenses (Boston Edison Company, D.P.U. 86-266-A (1985); and, certain nuclear outage expense (Western Massachusetts Electric Company, D.P.U. 87-260 (1988), Western Massachusetts Electric Company, D.P.U. 85-270 (1986)).

Only a small number remain in service today. Now that the Metscan devices have been removed in large part from service, Bay State seeks amortized recovery of the investment remaining.

Bay State seeks an amortization of the remaining investment without a return on that investment, not traditional rate base treatment. The question is not whether these assets are now used and useful: Bay State acknowledges they are have reached the end of their useful lives. However, the record amply demonstrates that the property was prudently acquired and duly in service (used and useful) to ratepayers for a decade. Exh. DTE-1-24; Wylde Wood Water Works, Inc., D.P.U. 86-93 (1987); Western Mass. Electric Company, D.P.U. 85-270 (1986); Fitchburg Gas and Electric Light Company, D.P.U. 19084 (1977); Fitchburg Gas and Electric Light Company v. Department of Pub. Utilities, 371 Mass. 881, 886-87 (1977); Fitchburg Gas and Electric Light Company, D.P.U. 18296/18297 (1975); Fitchburg Gas and Electric Light Company, D.P.U. 18031-A (1975); Fitchburg Gas and Electric Light Company, D.P.U. 18031 (1974).   In Bay State's view, these precedents should be followed ,and Bay State should be permitted to amortize the remaining balance of its prudently incurred Metscan investment.

d. Response to UWUA

The UWUA claims that the Metscan deployment was imprudent and Bay State's requested recovery of the amortization associated with the remaining investment should be disallowed. UWUA Br., at 65-67. However, there is no evidence in this record that supports a finding of imprudence. The UWUA's criticisms should be dismissed.

A prudence review must determine whether the utility's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances that existed at the time the investment was made. Boston Gas Company, D.P.U. 93-60, at 24. A determination of reasonableness and prudence may not properly be made on the basis of hindsight judgments, nor is it appropriate to merely substitute one's own judgment for the judgment of the management of the utility. Attorney General v. Department of Pub. Utilities, 390 Mass. 208, 229 (1983). A prudence review must base its findings on how a company reasonably should have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all the circumstances that were known or reasonably should have been known at the time the decision to make the decision was made. Boston Gas Company, D.P.U. 93-60, at 25; Western Massachusetts Electric Company, D.P.U. 85-270, at 23-24; Boston Edison Company, D.P.U. 906, at 165 (1982).

As described above, the Company determined to purchase telephone based technology after field-testing the equipment and evaluating its operations for two years; the failure of the Metscan technology was only apparent during the change-out of the meter batteries; and the Itron phase-in decision was made after due deliberation and analysis. The evidence clearly shows that at the time the relevant decisions were made, Bay State acted prudently. The UWUA has failed to demonstrate that Bay State was imprudent in deploying the Metscan devices, and therefore, the UWUA's recommended disallowance should be dismissed.

2. Adjustment to Remove Per Books Goodwill Amortization

The goodwill related to the Bay State/NIPSCo and the Lawrence Gas Company mergers was recorded to gas plant Account 303 for amortization on the books. Exh. BSG/JES-1, p. 41;

Exh. BSG/JES-1, at Sch. JES-8, p. 2. Bay State eliminated the per books amortization from Bay State's revenue requirement for ratemaking purposes. Id.

E. Other Intervenor Issues

1. Westborough Lease Costs

The UWUA challenges Bay State's inclusion of the Westborough building lease costs in Bay State's revenue requirement because it claims the building is "a virtual ghost town." UWUA Br., at 60. UWUA recommends Bay State be allowed to adjust no more than an arbitrary 10.95% above the UWUA-estimated-building-space-per-employee-cost in 2000. The recommended adjustment would reduce Bay State's annual lease cost of $1,069,105 (exclusive of sublease revenues) to $641,335, as a "reasonable lease cost." The UWUA calculation has no basis in rational ratemaking. The lease amount reflects the amount that Bay State is contracted to pay on an annual basis, for a building of reasonable size and location, and which lease terms were at market value at the time of execution; less the amount of sublease revenues that Bay State received, in order to reduce the lease payment obligation. Id.

For these reasons, UWUA's proposed adjustment to reduce recoverable lease expense for Bay State's Westborough headquarters should be rejected.

2. Legal Retainer

The Attorney General argues that allocating approximately $62,000 of the retainer for NiSource's primary outside counsel, the pre-eminent Chicago law firm of Schiff, Hardin &

Waite ("Schiff") and the services of the NiSource General Counsel, to Bay State is inappropriate. AG Br., at 67-68. The argument is without merit.

Schiff has a long-standing relationship with NiSource, having been its primary counsel when NiSource was formed with the Bay State/NIPSCo merger and through the integration of Columbia. Schiff continues as NiSource's leading business and transactional counsel, assisting NiSource on a wide variety of issues from union and human resources to real estate to corporate and holding company issues. The long-standing relationship and institutional knowledge are clearly substitutes for competitive bidding because ratepayers benefit from efficiencies created by a deep existing understanding of the parent corporation when legal advice is rendered. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 193 (2002). For his part, the NiSource General Counsel is the lead attorney for the corporation, a member of the Executive Counsel of the Corporation, and the chief supervisor of a staff of more than 30 lawyers in NCSC. The allocated expense is reasonable and more than justified by the ability of Bay State to have access to the Schiff skill and expertise.

3. Advertising and Promotion Expense

a. Response to Attorney General and MOC

The Attorney General claims that the sales and promotion expenses for EP&S included in the revenue requirement are improper. AG Br., at 75-78. MOC argues that the Department should disallow all of Bay State's advertising and sales promotional expenses. MOC Br., at 6-15. The MOC believes that the Department as a matter of policy should not encourage conversion programs during periods of high energy prices. MOC Br., at 4. MOC also alleges that Bay State failed to perform the required analyses to evaluate the propriety of advertising and sales promotional expenses.

Bay State disagrees. For advertising costs of $184,801 of above-the-line expense, Bay State demonstrated that all the costs were for EP&S which is beneficial to customers (because it adds revenues and lowers the overall requirement) and which is in direct competition with non-regulated products and services. Exh. BSG/JES-1, p. 72 (water heater rental, guardian care warranty service and fee for service); Exh. BSG/SHB-1, p. 52 (competition with non-regulated companies). Bay State has not and will not request recovery of any advertising costs that are below the line. Exh. MOC-1-3; Exh. MOC-3-10 (the $184,801 is above the line costs). The Company expended no money in the test year for "image enhancement" advertising. Exh. MOC-1-4(a).

For sales promotions programs totaling $1,191,844 (direct and indirect costs), Bay State demonstrated the benefit because the programs totaling $1,191,844 yield $5.7 million in net revenue from the EP&S business that directly reduces Bay State's revenue deficiency and reduces the obligation on customers. Exh. BSG/SHB-1, p. 58. Bay State explained that in order to ensure that ratepayers do not subsidize separate business activities and that ratepayers share in any benefits attributable to these activities, it ensures that the appropriate incremental costs and revenues were allocated to these businesses. Exh. BSG/SHB-1, pp. 56-57.[47] In 2000, the

[47] In Bay State Gas Company, D.P.U. 92-111 (1992), the Department determined that the appropriate accounting treatment for above-the-line activity was an incremental approach to such activities.

Department accepted Bay State's request to account for service business costs on a fully allocated basis, rather than following the Department's incremental cost approach. Exh. BSG/SHB-1, p. 56-57. As a result the appropriate level and kind of costs are captured and allocated to these activities, providing greater assurance that EP&S continues to generate net benefits for ratepayers. Bay State's inclusion of EP&S advertising, sales and promotions expenses are an appropriate and reasonable cost of doing business that directly benefits ratepayers. Accordingly, the Attorney General and the MOC's challenges in this regard should be dismissed.

4. <u>Corporate Air Transport Expense</u>

The Attorney General challenges the inclusion of the allocated share of employee transportation expenses via the NiSource corporate aircraft. AG Br., at 82. The aircraft, is a single small jet used strictly to transport officers and employees between the 11-states that comprise the NiSource system. RR-AG-45; RR-AG-46. Bay State demonstrated that the expense is necessary for the officers of NiSource because the system is so large and travel so frequent that it permits them to continue working while conducting business and reach their destinations more rapidly. It is important to note that the corporate aircraft is regularly shared by non-officer employees who require travel in their duties. RR-AG-45. 190 flights occurred between Columbus, Ohio and Merrillville, Indiana carrying several employees each time during the test year. RR-AG-45. Moreover, many of the NiSource operating companies are not in airport "hubs." Without the company aircraft in these situations, multiple connections would be necessary. The aircraft is an effective and efficient way to move employees around the country on business when conventional routes are more expensive or would involve unnecessary delay. The allocated costs to Bay State should be included in the cost of service.

5. Penalties and Late Fees

The Attorney General also argues that Bay State included late fees and penalties (such as Dig Safe) in its operating expenses. AG Br., pp. 82-83. First, with regard to late fees, Bay State acknowledges that those were in the revenue requirement and now state they should have been removed from operating expense for the test year. RR-AG-93.

However, that is the only area of agreement.

The Attorney General's assertion about Dig Safe penalties disregards the record evidence. The sworn testimony and evidence demonstrates that Bay State books penalties associated with Dig Safe (in the test year $6,500) below the line in a separate account, Account 426-50. Exh. AG-1-83 Supp; Tr., at 814-15. The recommended disallowance makes no sense.

The Attorney General also believes that Bay State should not have included its self insurance adjustment covering settlements and judgments in its cost of service.[48] This recommendation is also unwarranted. The Department has recognized that a company's ability to control costs through self-insured claims is an important hedge against the rising cost of insurance premiums. Bay State Gas Co., D.P.U. 92-111, at 110 (1992). Liability insurance is a normal and prudent cost of doing business. The Attorney General seems to suggest, contrary to

[48] The Attorney General claims that there is $250,310 in the cost of service amount for settlements and judgments; however, per Exh. RR-AG-25, the amount for self insurance claims is $215,300. Among other reasons, the Attorney General's recommended disallowance should be rejected because it is inaccurate. Compare AG Br., at 83 with Exh. RR-AG-25.

the Department precedent, that including in operating expense the cost of conventional insurance premiums with a nominal deductible is preferable to self insurance, where the amount in rates only reflects one-fifth of actual claims based on a five-year average of actual payments. Exh. BSG/SHB-1, p. 20. The self insurance amount is lower, reasonable and reflects a prudently incurred business expense.

Finally, the Attorney General claims that Bay State included conversion fees in operating expense. AG Br., at 84. That is not the case, and once again, the Attorney General's assertion belies the record evidence. Mr. Skirtich and Mr. Ferro both testified that these amounts were removed from operating expense through Mr. Ferro's annualization process..[49]

F. Taxes Other Than Income

1. <u>Property Taxes</u>

The Department bases property taxes on the most recent property tax bills a utility receives from the communities in which it has property. <u>Fitchburg Gas and Electric Light Company</u>, D.T.E. 02-24/25, at 123; <u>Boston Gas Company</u>, D.P.U. 96-50 (Phase I), at 109; <u>Colonial Gas Company</u>, D.P.U. 84-94, at 19 (1984). The property taxes for ratemaking purposes were determined at the outset by totaling all such bills. Exh. BSG/JES-1, p. 42; Exh. BSG/JES-1, at Sch. JES-9, p. 2. The amount determined to be in excess of the test year amount provided an increase in property tax expense of $312,217. Exh. BSG/JES-1, p. 42; Exh. BSG/JES-1, at

[49] The Attorney General also claims that line repair reimbursements paid to customers for the failing Metscan devices were not appropriately includable in operating expense. It is illogical to connect this operating expense with a "fee or penalty." See, Tr., at 141 (few line reimbursements in number compared to the 250,000 installed devices); Exh. AG-21-3. There is no connection. This clearly falls within the ebb and flow of operating expenses, and the recommended disallowance of $14,000 should be rejected.

Sch. JES-9, p. 2, Col. 1, Line 3. An appropriate allocation to Northern was deducted for its use of common facilities, providing a total property tax adjustment of $310,710. Exh. BSG/JES-1, pp. 41-42; Exh. BSG/JES-1, at Sch. JES-9, p. 2, Col. 1, Line 6.

No party has challenged Bay State's request to recover property tax in this proceeding.

2. Payroll Taxes

Bay State made an adjustment to test-year payroll taxes to provide for the increase in FICA payroll tax related to the pro forma increase in payroll, increasing the test-year payroll taxes by $91,114. Exh. BSG/JES-1, p. 43; Exh. BSG/JES-1, at Sch. JES-9, p. 4, Col. 3, Line 7.

No party has questioned the manner or method of adjusting payroll taxes to accommodate the increase in payroll, if it is approved by the Department as requested by Bay State.

G. Interest on Customer Deposits

Bay State adjusted its per books test-year expense to reflect pro forma adjustments to account for the interest paid on customer deposits based on the interest rate established by the Department. Exh. BSG/JES-1, pp. 44-45; Exh. BSG/JES-1, at Sch. JES-10, Col. 1, Line 3. The adjustment increases O&M expense by $72,506. Id.

No party has questioned this calculation.

H. Federal Income and Massachusetts Franchise Tax

SFAS 109 required companies, effective December 31, 1992, to record on their financial statements all future income tax liabilities. Exh. BSG/JES-1, p. 45. Because utilities subject to cost of service ratemaking are allowed to recover income tax liability in rates, and the benefits of certain tax depreciation deductions, they were allowed to record an offsetting net regulatory asset representing the future recovery of the income tax liability in rates. Exh. BSG/JFS-1, p. 45. Bay State recorded a net regulatory asset and future tax liability related to Federal and State income taxes since adopting SFAS 109. Exh. BSG/JFS-1, p. 45. Bay State presented the computation of Massachusetts State Franchise Taxes and Federal Income Taxes calculated using the rate base and rate of return methodology according to Department standard. Exh. BSG/JES-1 at Sch. JES-11. In addition, the computation provides for the amortization of the net regulatory asset resulting from the application of Statement of Financial Accounting Standards ("SFAS") 109, "Accounting for Income Taxes," relating to both Federal Income and Massachusetts State Franchise Tax. Id.

In D.P.U. 92-111, the Department approved recovery of the Company's total deficiency of $4,385,240 over approximately 25 years. Annual amortization of the deficiency was $174,017. Id. At December 31, 2004, $2,286,034 remained. Id. However, as a result of the Federal Income tax rate change from 34% to 35% and to update for 1992 differences, the last year when the tax rate was 34% an additional $1,167,619 of revenue deficiency exists. Id. In this proceeding, Bay State proposes to amortize this deficiency over the remaining amortization period or 13.0334 years. Exh. BSG/JES-1; Exh. BSG/JES-1 at Sch. JES-11. The amortization includes a total of the $263,604; $174,017 approved by the Department in D.P.U. 92-111 for recovery by Bay State, and provides for $89,587 for the additional calculated deficiency. Id.

In D.P.U. 92-111, the Department approved recovery of the Company's total deficiency of $4,385,240 over approximately 25 years. Exh. BSG/JES-1 at p. 46; Exh. D.P.U. 92-111 at

170-73. Annual amortization of the deficiency was $174,017. Id. At December 31, 2004, $2,286,034 remained. Exh. BSG/SHB-1, p. 46. However, as a result of the Federal Income tax rate change from 34% to 35% and to update for 1992 differences, the last year when the tax rate was 34% an additional $1,167,619 of revenue deficiency exists. Exh. BSG/SHB-1, p. 46. In this proceeding, Bay State proposes to amortize this deficiency over the remaining amortization period or 13.0334 years. Exh. BSG/JES-1 at 46; Exh. BSG/JES-1 at Sch. JES-11. The amortization includes a total of the $263,604; $174,017 approved by the Department in D.P.U. 92-111 for recovery by Bay State, and provides for $89,587 for the additional calculated deficiency. Exh. BSG/SHB-1, p. 46.

a. Response to Attorney General relative to ADIT

The Attorney General complains that the Department should deny the Company's proposed adjustment in accumulated deferred income taxes because the adjustment is inconsistent with Generally Accepted Accounting Principles (GAAP). AG Br., at 81-82 The Attorney General also argues that the amount should be adjusted based on the amounts presented in D.P.U. 92-111 because those amounts were known and measurable. The Attorney General also argues that the amount should be adjusted based on the amounts presented in D.P.U. 92-111 because those amounts were known and measurable.

The Attorney General's proposal indicates his misunderstanding of this issue, and his recommendation has no merit. Bay State did follow GAAP in not amortizing the additional deferred income taxes. The 1992 case was based on test year 1991. Bay State did not file its tax return until September 1992 so the timing difference was not measurable, and therefore could not have been included in the 1992 case. The South Georgia method, used by Bay State, is consistent with GAAP. It allows only for an adjustment in the amortization approved by the governing regulatory commission. Tr., at 3881-82; 78 F.E.R.C. ¶62,135, 1997 FERC LEXIS 2837 (Jan. 31, 1997).

I. Depreciation Annualization

Bay State's proposed depreciation expense is $28,800,958, an increase of $4,651,387 over book depreciation, once the appropriate allocation of $66,839 is made to share the cost of common facilities with Northern. Exh. BSG/JES-1, p. 38; Exh. BSG/JES-1, at Sch. JES-7, pp. 1-2. In order to annualize depreciation expense at the proposed depreciation rates and to reflect an additional $22,864 of depreciation associated with non-discretionary CWIP completed and in service, Mr. Skirtich made a further adjustment. Mr. Skirtich recognized that Bay State had $1,053,621 of non-discretionary plastic mains investment in its CWIP as of the end of the test year that were actually in service and completed, but due to timing had not been moved into plant. Exh. BSG/JES-1, p. 40. The annualized depreciation expense is a net increase to O&M of $4,674,251. Exh. BSG/JES-1, p. 40; Exh. BSG/JES-1, at Sch. JES-7, p. 1.

Bay State's depreciation rates are based on a depreciation study prepared for Bay State by Earl M. Robinson of AUS. Exh. BSG/EMR-2. Mr. Skirtich applied the new depreciation rates supported by the Robinson depreciation study to the test year end depreciable plant, in order to annualize deprecation expense. Exh. BSG/JES-1, p. 39; Exh. BSG/JES-1, at Sch. JES-7, p. 3 (provides gross depreciable plant by gas plant account).

VIII. DEPRECIATION

A. Introduction

Bay State presented a comprehensive depreciation study prepared by Earl M. Robinson, President and Chief Executive Officer of the Weber Fick & Wilson Division of AUS Consultants - Utility Services. Exh. BSG/EMR-1, pp. 1-2. Mr. Robinson's study developed new depreciation rates for the Company's plant accounts as of December 31, 2003. Exh. BSG/EMR-2. The methodology used for the study is set forth in Mr. Robinson's direct testimony. Exh. BSG/EMR-1, pp. 6-31. Applying the proposed individual account level depreciation rates, determined by the study, to the Company's plant in service as of December 31, 2004 produces a composite annual depreciation rate of 4.24%. Exh. BSG/EMR-1, p. 31. The proposed annualized depreciation expense increases test year depreciation expense by $4,651,387. Exh. BSG/JES-1, at Sch. JES-7, pp. 1-4; Exh. BSG/JES-1, pp. 38-40.

Mr. Robinson is a Certified Depreciation Professional and has been an expert in depreciation matters for over 30 years. Tr., at 1792. He has performed many depreciation studies for the natural gas, electric, telecommunications, water, wastewater and cable TV industries. Exh. BSG/EMR-1, Appendix A, pp. 3-5. Mr. Robinson is an active member in depreciation organizations such as the Society of Depreciation Professionals, the AGA Accounting Services Committee, and the EEI Plant and Property Accounting Committee. Exh. AG-8-32.

B. Depreciation Defined

In the 1996 NARUC publication, "Public Utility Depreciation Practices," depreciation is defined, in pertinent part, as

> "the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities."

Exh. BSG/EMR-1, pp. 2-3.

Depreciation is important for a utility because depreciation expense enables a company to recover, in a timely manner, the capital costs related to its plant in service for the benefit of customers. Exh. BSG/EMR-1, p. 3. Appropriate depreciation rates will allow recovery of a company's plant investments over the appropriate service lives for those investments, which provides for full recovery of the investments, less net salvage. Exh. BSG/EMR-1, p. 3. If depreciation rates are too low, capital costs will be underrecovered prior to the retirement of the plant. In that situation, future customers will subsidize current customers because current customers would have received the benefits of the plant in service without incurring their appropriate share of the costs of that plant. Exh. BSG/EMR-1, p. 3; Exh. AG-8-29.

C. Department Standards

In numerous decisions, the Department has confirmed these depreciation principles. The Department permits depreciation expense in rates because it allows a company under its jurisdiction to recover its capital investments in plant in service in a timely and equitable fashion over the service lives of the investments. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132; Boston Gas Company, D.P.U. 96-50 (Phase I), at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985). Depreciation studies rely not only on statistical analysis, but also on the judgment and expertise of the preparer. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132.

When a witness reaches a conclusion about a depreciation study that varies from that witness's engineering and statistical analysis, the Department will not accept such a conclusion without sufficient justification on the record. Id., citing Cambridge Electric Light Company, D.P.U. 92-250, at 64; Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One), at 54-55 (1991); Commonwealth Electric Company, D.P.U. 88-135/151, at 37 (1990); Berkshire Gas Company, D.T.E. 01-56, at 93. The Department will, however, look beyond the numbers presented in a study when sufficient justification is presented. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132. It is also necessary to go beyond the numbers presented in a depreciation study and consider the underlying physical assets. Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department requires gas companies to prepare a gas mains material study with each depreciation study. Berkshire Gas Company, D.T.E. 01-56, at 95. Any gas mains material study should include proposed material-specific accrual rates. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 134, n. 62.

If a depreciation accrual rate is set too low, capital costs will be underrecovered prior to the retirement of the plant. Fitchburg Gas and Electric Company, D.T.E. 02-24/25, at 137.

Future ratepayers will subsidize past and current ratepayers, because past and current ratepayers would have received the benefits of the plant without incurring their appropriate share of the costs of that plant. Boston Gas Company, D.P.U. 19470, at 51 (1978). Where the Department determines that underaccruals have developed because of neglectful practices of management, ratepayers should not bear the financial burden of such negligence. Boston Gas Company, D.P.U. 19470, at 49-50; Wannacomet Water Company, D.P.U. 13525, at 20 (1962).

Depreciation accrual rates are applied to the test year-end depreciable gas plant in service balance. Fitchburg Gas and Electric Company, D.T.E. 02-24/25, at 146. Net salvage values are determined qualitatively, not statistically. Id., at 134.

D. Bay State's Depreciation Study

Bay State's depreciation study included an analysis of the Company's historical plant retirement data, together with an interpretation of the Company's past experience and future expectations for its plant in service, to determine the appropriate remaining lives and net salvage values for that plant. Exh. BSG/EMR-1, p. 2. The remaining lives, the results of the salvage analysis, the Company's vintaged plant in service investment and the depreciation reserve were all considered in developing the Company's proposed depreciation rates. Exh. BSG/EMR-1, p. 2.

The depreciation study performed by Mr. Robinson began with a detailed analysis of the Company's plant accounts through December 31, 2003. Exh. BSG/EMR-1, p. 6. From the plant account records, a historical database was assembled and used to make assessments and judgments concerning service lives and salvage factors. Exh. BSG/EMR-1, p. 6. Using the historical data and information from Company personnel relative to current and prospective factors affecting the retirement of plant, Mr. Robinson determined the appropriate future lives over which to recover the Company's investment in depreciable plant and net salvage values. Exh. BSG/EMR-1, pp. 6-7.

The historical database compiled through December 31, 2003 was used to develop observed life tables by grouping like-aged investments within each property category and identifying the level of retirements that have occurred through each successive age. Exh. BSG/EMR-1, p. 7. The survivor curves (or observed life tables) were then fitted to standard Iowa curves to estimate each (property) group's historically achieved average service life. Exh. BSG/EMR-1, p. 7.

Net salvage consists of the proceeds received from the sale or disposition of a unit of property (gross salvage), less the cost of removal. Exh. BSG/EMR-1, p. 18. When the cost of removal exceeds gross salvage, the net salvage value will be negative. Exh. BSG/EMR-1, p. 18. Mr. Robinson developed a net salvage database based on the Company's net salvage experience from 1980-2003 which was used to identify historical experience and trends. Exh. BSG/EMR-1, p. 7. Mr. Robinson prepared three-year rolling band analyses of net salvage, as well as forecasts of net salvage based on the Company's historical salvage experience. Exh. BSG/EMR-1, p. 7. Mr. Robinson obtained information from Company personnel concerning current operations and future expectations for plant retirement, conducted on-site visits to various Company operation centers, interviewed Company operations management and physically inspected representative operating property. Exh. BSG/EMR-1, pp. 7-8; Exh. AG-5-4; Exh. DTE-11-1, Exh. DTE-11-2, Exh. DTE-11-3; Tr., at 1798-99. Mr. Robinson also incorporated his professional knowledge, from more than 30 years of utility industry depreciation experience, in recommending average service lives and net salvage values for the Company's plant accounts. Exh. BSG/EMR-1, p. 8.

The depreciation study is entitled "Bay State Gas Company Depreciation Study as of December 31, 2003" and summarizes the results of Mr. Robinson's service life and salvage analysis. Exh. BSG/EMR-2. All of the historical data contained in the study used for the detailed service life and salvage analysis was obtained from the books and records of the Company. Exh. BSG/EMR-1, p. 9.

The two key sections of the depreciation study are Sections 2 and 4. Exh. BSG/EMR-1, p. 8. Section 2 includes the summary schedules listing the present and proposed depreciation rates for each depreciable property group. Exh. BSG/EMR-1, p. 8; Exh. BSG/EMR-2, Section 2. Section 4 contains a narrative describing the factors considered in selecting service life and net salvage for the various property groups. Exh. BSG/EMR-1, p. 8; Exh. BSG/EMR-2, Section 4.

In his direct testimony, Mr. Robinson explained the overall methodology used for the depreciation study. A comprehensive depreciation study requires the choice of a method, a procedure and a technique. Exh. BSG/EMR-1, pp. 9-27.

Mr. Robinson's service life analysis used the Retirement Rate Method. Exh. BSG/EMR-1, pp. 9-10. This method is used when a company maintains aged plant records, as does Bay State. Exh. BSG/EMR-1, p. 9. The Company's actuarial service life data was used to develop survivor curves (or observed life tables). Exh. BSG/EMR-1, p. 24. The standard Iowa curves, or smooth curves, were fitted to the survivor curves to determine the average service life being experienced by the property account under study. Exh. BSG/EMR-1, p. 24. Various experience bands within the total lives of an account can allow for the observation of trends and changes. Exh. BSG/EMR-1, pp. 24-25.

Due to the existence of very large quantities of property units, utility property is typically grouped into homogenous categories as opposed to being depreciated on an individual unit basis. Exh. BSG/EMR-1, p. 10. There are several procedures that can be used to arrange or group property by sub-groups of vintages. Exh. BSG/EMR-1, p. 10. Two common procedures used are the Broad Group and Equal Life Group procedures. Exh. BSG/EMR-1, p. 10. The Broad Group procedure is more widely utilized than the Equal Life Group procedure by utility regulatory commissions as a basis to determine depreciation rates. Exh. BSG/EMR-1, p. 11. The Broad Group procedure is consistent with depreciation methods and procedures generally accepted by the Department and is the approach underlying the depreciation rates approved by the Department in D.P.U. 92-111, Bay State's last full base rate proceeding. Exh. BSG/EMR-1, p. 14. An example of the differences between the Broad Group and Equal Life Group procedures is presented by Mr. Robinson in Exhibit BSG/EMR-1, pp. 11-12.

Depreciable plant must be recovered over a defined period of time using a technique such as the Whole Life or Average Remaining Life of the property group. Exh. BSG/EMR-1, p. 12. Under the Whole Life technique, the depreciation rate is based on recovery of the investment and average net salvage over the average service life of the property group. Exh. BSG/EMR-1, p. 12. In contrast, under the Average Remaining Life technique, the resulting annual depreciation rate incorporates the recovery of the investment (and future net salvage) less any recovery realized to date over the average remaining life of the property group. Exh. BSG/EMR-1, pp. 12-13. The Average Remaining Life technique is the superior technique in that it incorporates all of the current and future cost components in setting the proposed annual depreciation rate, thereby better assuring full recovery of the utility's embedded net plant investment and related costs. Exh. BSG/EMR-1, pp. 13-15. It also recognizes the level of depreciation which has been accrued to date in developing the proposed depreciation rate. Exh. BSG/EMR-1, p. 15. This technique is often used by regulated companies and regulatory agencies because it allows full recovery of plant investment by the end of the property's useful life – no more and no less. Exh. BSG/EMR-1, p. 15.

E. The Attorney General's Proposals

The Attorney General recommends a $626,162, or 2.6%, decrease in depreciation expense from current test year levels. AG Br., at 54-55. This represents a difference of $5,594,252 from Bay State's proposed depreciation rates. AG Br., at 54-55. In support of this proposal, the Attorney General sponsored the testimony of Jacob Pous from Diversified Utility Consultants, Inc.

Mr. Pous did not perform a complete depreciation study of all of the Company's accounts. Mr. Pous, unlike Mr. Robinson, also did not inspect any of Bay State's plant. Instead, he focused on only two of the Company's plant accounts, Account 376 - Mains and Account 380 - Services, because the majority of the Company's investment is included in these two accounts and, with only these two accounts, he could most easily propose the largest financial impact on the Company's depreciation proposal. Exh. BSG/Rebuttal-4, p. 1; Exh. AG-6, p. 4.

For Account 376 - Mains, Mr. Pous proposes a net negative salvage of -10%, whereas Mr. Robinson recommends a negative net salvage of -15%. Exh. AG-6, p. 4; Exh. BSG/Rebuttal-4, p. 2. For Account 380 - Services, Mr. Pous proposes a negative net salvage of -110%, whereas Mr. Robinson recommends a negative net salvage of -170%. Exh. AG-6, p. 4; Exh. BSG/Rebuttal-4, pp. 2-3. These two adjustments would reduce the Company's proposed test year depreciation expense by $3,757,131. Exh. AG-6, p. 4.

For two subaccounts within Account 376 (Accounts 376.2, Steel Mains/Coated Wrapped and 376.4, Plastic Mains), Mr. Pous proposes different average service lives and Iowa curves than Mr. Robinson recommends, resulting in a reduction to the Company's test year depreciation expense of $1,922,219. Exh. AG-6, pp. 4-5; Exh. BSG/Rebuttal-4, pp. 14-19.

Finally, the Attorney General requests that the Department order a more detailed justification for the net salvage levels in the Company's next depreciation study. AG Br., at 56.

F. Bay State's Rebuttal to the Attorney General's Proposals

Mr. Robinson presented extensive rebuttal testimony explaining why each of Mr. Pous' recommendations should be rejected by the Department. Exh. BSG/Rebuttal-4.

Mr. Pous chose to address only two plant accounts. Exh. AG-6, p. 4; Exh. BSG/Rebuttal-4, p. 1. However, a valid depreciation study must include all of the various property groups in a utility's plant in service. It is customary in a complete depreciation study that the recommended depreciation rates when compared to current rates display variances in both directions, up and down. Confining an examination exclusively to the two largest property groups simply does not present a complete picture necessary for the Department to make an informed decision on the depreciation rates of the Company. For this reason alone, Mr. Pous' recommendations should be rejected.

Another fundamental shortcoming of Mr. Pous' approach is that he relies exclusively on the Company's historical data, and then only on selected historical data, and gives little or no consideration to the factors that will affect future net salvage values for various plant accounts. He, therefore, ignores a basic tenet of the Average Remaining Life technique used by Mr. Robinson, i.e., that the levels of future net salvage must be considered when proposing depreciation rates in addition to the levels of a company's historical net salvage. Exh. BSG/Rebuttal-4, p. 4.

1. Account 376 - Mains

Mr. Pous recommends a -10% net salvage for Account 376-Mains rather than Mr. Robinson's -15% net salvage. Exh. AG-6, p. 4. In objecting to Mr. Robinson's recommended -15% net salvage, the Attorney General states that, under Mr. Robinson's proposed rate for this account, the Company would be seeking $1.64 in depreciation expense for every dollar of plant investment. AG Br., at 56. This result, however, is not at all unexpected, given that the plant accounts for Bay State, as well as those for most other gas companies, routinely experience far more negative salvage than positive salvage. Therefore, full recovery of the total cost of that asset will typically be greater than the original cost of the asset.

Mr. Pous' -10% net salvage proposal is based on only certain data from the Company's historical net salvage records for this account. Mr. Pous claims that, because in the past 10 years the Company's actual net salvage exceeded -15% in only two of those years, the Company should not change its current net salvage of -10% for Account 376. Exh. AG-6, p. 12. However, Mr. Pous ignores the fact that in six of those 10 years the Company's net salvage exceeded the current -10% rate. Exh. BSG/Rebuttal-4, p. 4. He also ignores the fact that, if all of the Company's historical net salvage data since 1980 is considered, there are many years in which the Company's net salvage was far above -15%. Exh. BSG/EMR-2, p. 7-19. With respect to the Company's three year rolling band analysis, the Attorney General uses only the past nine three year rolling bands and not the entire history of the account. AG Br., at 58. Using nine rather than 10 years excludes a significant data point where negative net salvage was -17.96%, far above the current -10%. Exh. BSG/EMR-2, p. 7-20. All of these facts demonstrate that Mr. Pous' -10% net salvage recommendation is wholly inadequate.

Mr. Pous gives no consideration to the fact that the future costs of removal for this account will continue to increase. BSG/Rebuttal-4, p. 4. Mr. Robinson performed a forecast analysis using an annual inflation rate of 2.75% that indicated a forecasted net salvage for this account of -22.58%, well above the -15% recommendation for the account. Exh. BSG/EMR-2, p. 7-21. Mr. Robinson pointed out that the future costs of removal for this account will be influenced by many cost increases including labor cost increases, increased costs of permitting, increased street restoration costs, and increased public safety and traffic control costs (police details). Exh. AG-8-21; Exh. AG-5-18. In any event, Mr. Robinson's forecasts of net salvage, on their own, were not used to determine the net salvage amount for this account, but rather to serve as a check on the reasonableness of Mr. Robinson's -15% recommendation and to demonstrate that his -15% net salvage figure is conservative. Exh. BSG/Rebuttal-4, pp. 4-5; Exh. BSG/Rebuttal-4, p. 2.

Mr. Pous criticized Mr. Robinson for not adhering strictly to the actual forecast of future net salvage. Exh. AG-6, pp. 13-14. As Mr. Robinson explained, however, these forecasts are merely an analytical tool to be used in arriving at the estimates of future net salvage and should not be used, alone, to determine the net salvage factors that are recommended. Exhs. AG-8-15, 8-16, 8-18, 8-28; Exh. DTE 11-15. Selecting a more conservative net salvage percentage than that which is indicated by the forecast analysis does not mean that the forecast is flawed. It simply means that it is prudent not to move all at once to the results indicated by the forecasts.

Other factors ignored by the Attorney General's witness will contribute to higher net salvage costs in the future. For example, Mr. Pous failed to take into account the fact that the Company's recently initiated steel replacement program will generate additional levels of future retirement costs for this account. Exh. BSG/Rebuttal-4, p. 4.

Mr. Pous asserted that "if Mr. Robinson's model were valid, one could plot the percentage relationship for cost of removal to retirements against the age of the retirements and observe a line sloping upward as age increase [sic]." Exh. AG-6, p. 14. In his rebuttal testimony, Mr. Robinson pointed out a number of errors in Mr. Pous' assertion. Mr. Pous used net salvage instead of cost or removal in plotting the property retirement age against the cost of removal. Exh. BSG/Rebuttal-4, p. 7. Furthermore, the Company's cost of removal data does not permit identification of the cost of removal by the age of plant retired. Exh. BSG/Rebuttal-4, p. 7. Therefore, there is no direct linkage between the specific age and dollar amount of a retirement and the corresponding cost of removal in the Company's data. Exh. BSG/Rebuttal-4, pp. 7-8. Nevertheless, Mr. Robinson was able to correctly capture the relationship of the Company's cost of removal and the average age of retirements with a linear regression analysis, which does produce a line sloping upward as age increases. Exh. BSG/Rebuttal-4, at Exhibit EMR-R1. Therefore, Mr. Robinson's linear forecast of cost of removal is, in fact, valid. Mr. Pous simply used incorrect data in his analysis and data plotting.

The Attorney General has found fault with Mr. Robinson's analysis, not because it is incorrect, but because Mr. Robinson could not define the R squared statistic on cross-examination. AG Br., at 58. The fact that Mr. Robinson could not define the terms in the statistical program he used does not undermine his analysis or his overall ability as an expert in the field of depreciation. Commonwealth Electric Company, D.P.U. 89-114/90-331 91-80 (Phase One), at 52.

The Attorney General appears to assert that proper depreciation accounting requires the cost of removal to be booked to the cost of new installation. AG Br., at 58; Exh. AG-6, p. 16. He claims that this procedure, if followed, would support the -10% net salvage recommended by Mr. Pous. AG Br., at 58-59. The Massachusetts Uniform System of Accounts for Gas Companies requires, however, that the cost of removal be booked to the Reserve for Depreciation, Account 254. Exh. BSG/Rebuttal-4; Exh. BSG/Rebuttal-4, at Exh. EMR-R2, p. 2. Bay State is reviewing its accounting practices to ensure compliance with the prescribed procedure, but to the extent Bay State has charged the cost of removal to new installations, that would understate the Company's actual costs of removal. Exh. BSG/Rebuttal-4, pp. 9-10.

The results of depreciation studies performed for other gas companies show that Mr. Robinson's recommended -15% net salvage for Mains is conservative. For the sixteen gas companies for which Mr. Robinson has data listed on Exhibit BSG/Rebuttal-4, Exh. EMR-R3, all have negative net salvage percentages for Mains of between -15% and -75%. Moreover, the New England gas companies on the list have negative net salvage percentages of between -20% and -75%. Exh. BSG/Rebuttal-4, at Exh. EMR-R3. The 1998 AGA Survey shows a mean average negative net salvage of -36%. Exh. BSG/Rebuttal-4, Exh. EMR-R3. All of this data provides additional support for the -15% net salvage factor proposed by Mr. Robinson.

2. Account 380 - Services

Mr. Pous recommends for Account 380 - Services a net salvage of -110%, instead of the -170% recommended by Mr. Robinson. Exh. AG-6, p. 4; Exh. BSG/Rebuttal-4, p. 2.

Not even the Company's historical data supports Mr. Pous' recommendation. It appears that his proposal is based on selecting an average of the negative net salvage values for the 4 years during the past 10 years that have experienced the largest dollar level of retirement activity. Exh. BSG/Rebuttal-4, p. 13. Mr. Pous simply ignored the Company's remaining net salvage data for this account.

In the majority of years dating back to 1980, the Company's net salvage has been far above -110% and in some cases it has been in excess of -200%. Exh. BSG/EMR-2, p. 7-25; Exh. BSG/Rebuttal-4, p. 9. In the Company's rolling band analysis, the most recent four bands dating back to 1998 show that negative net salvage has been well above -110%. Exh. BSG/EMR-2, p. 7-26. The Company's actual historical experience for the account over all years for which data is available shows a net salvage percentage of -171.17%. Exh. BSG/EMR-2, pp. 7-27. Although Mr. Robinson's forecasted net salvage analysis indicated a net salvage for this account of -403.72%, he did not recommend increasing the net salvage beyond -170%. Exh. BSG/EMR-2, pp. 7-27.

The Attorney General claims support from the fact that the negative net salvage for the Services account recommended by Mr. Robinson is approximately 11 times larger than the net salvage recommended for the Mains account. AG Br., at 60.

The Attorney General, however, has ignored Mr. Robinson's testimony that the cost of removal for Services will be far greater than that for Mains because of the relatively greater level of retirement activity for the level of original cost that is required for Services compared to Mains. Exh. BSG/Rebuttal-4, p. 11. That is because each Service that must be disconnected and purged when retired is relatively short with a low original cost, whereas disconnections for Mains occur for much longer lengths of pipe with a much higher original cost. Exh. BSG/Rebuttal-4, p. 11.

Mr. Pous implied that a single 1994 net salvage value of -1,724% undermines the Company's historical net salvage data for Services. p AG-6, pp. 20-21; Exh. BSG/EMR-2, pp. 7-25. Mr. Robinson explained, however, that the reason for the extremely high negative net salvage in 1994 was the fact that the dollar amount of the 1994 retirements was extremely low in comparison to years prior to, and after, 1994. Exh. BSG/Rebuttal-4, pp. 11-12. The high negative net salvage was simply caused by the timing of retirements, which is not always synchronized with net salvage transactions recorded in the same accounting period. Exh. BSG/Rebuttal-4, p. 12.

The Attorney General also criticizes Mr. Robinson for recommending a net negative salvage of -170% for the Services account in this proceeding, while recommending -55% in a Louisville Gas & Electric Company case and -40% in a Kansas Gas Services Company case. AG Br., at 61 and fn. 37.

This criticism has no merit. Although the salvage percentages recommended in those cases were less negative than the level proposed for Bay State in this case, the related average service lives for Services in those cases were only approximately 50-60% of the length of the average service lives being recommended for Bay State in this case. Exh. BSG/Rebuttal-4, pp. 12-13. Therefore, it is to be expected that the negative net salvage figures in those cases would be substantially less negative than what is required for Bay State here. Exh. BSG/Rebuttal-4, p. 13. In addition, as Mr. Robinson pointed out in his rebuttal testimony, he has prepared depreciation studies in other cases which have resulted in net negative salvage percentages for Services that are equal to or higher than what has been recommended for Bay State in this case. Exh. BSG/Rebuttal-4, p. 13. The -170% net negative salvage is therefore, reasonable when considering the recommendations of Mr. Robinson in cases involving other companies.

Mr. Robinson's recommended -170% net salvage for Services is also entirely consistent with the net salvage levels used in depreciation studies of other New England gas companies. Exh. BSG/Rebuttal-4, Exh. EMR-R3. Those companies have net salvage percentages ranging of from -60% to -175%, and 5 of the 7 companies listed by Mr. Robinson have net salvage percentages greater than the -110% recommended by Mr. Pous. Exh. BSG/Rebuttal-4, at Exh. EMR-R3.

Finally, in light of the support in the record for Mr. Robinson's recommended net salvage factors, there is no basis for an order from the Department, as suggested by the Attorney General, requiring the presentation of a more detailed justification of the net salvage factors in the Company's next depreciation study.

3. Average Service Lives (Account 376.4 Plastic Mains, Account 376.2 Coated/Wrapped Steel Mains)

a. Account 376.4, Plastic Mains

With regard to Mr. Pous' average service life recommendation for Account 376.4 - Plastic Mains, his graphical presentation was plotted in a manner that made the variances between his recommended Iowa life and curve (68-S1.5) and the Iowa life and curve underlying Bay State's depreciation rates (55-S2) appear far larger than they really are. Exh. BSG/Rebuttal-4, p. 14. Moreover, Mr. Pous admitted that he ignored the data beyond 25 years of age. Exh. AG-6, p. 32. Mr. Pous incorrectly assumed that Mr. Robinson also did not rely on the dramatic change in the survivor curve between the ages of approximately 25 and 26. Exh. BSG/Rebuttal-4, pp. 14-15. Mr. Robinson testified, however, that he did not, in fact, ignore the data beyond 25 years of age. Exh. BSG/Rebuttal-4, p. 16. Although there were some limited levels of early plastic main vintage retirements, far greater portions of the plastic mains retirements occurred during the years 1978 and later. Exh. BSG/Rebuttal-4, p. 15. These significant levels of plastic main retirements have occurred as a result of all causes of retirements (not just physical attributes as Mr. Pous suggested) and will continue to occur at increasing levels during future years. Exh. BSG/Rebuttal-4, pp. 15-16.

An even more significant factor supporting Mr. Robinson's service life recommendation is the result of the various data analyses completed relative to plastic mains. Exh. BSG/Rebuttal-4, p.16. Mr. Robinson's analysis of all the historical data points relative to plastic mains indicated a service life represented by an Iowa 41-S2 life and curve. Exh. BSG/Rebuttal-4, p.16. While he interpreted that the level of retirements beyond age 25 was likely proportionately somewhat larger than would be experienced in coming years, he also estimated that future retirements from older vintage aged retirements will nevertheless continue to occur, albeit at a proportionately somewhat lower level. Exh. BSG/Rebuttal-4, p. 16. Accordingly, to estimate the ultimate proposed service life for this property category, Mr. Robinson prepared an additional analysis in which he truncated the retirement age data at 25 years (i.e., ignored the data more than 25 years of age) and determined the indicated average service life for the Iowa S2 curve. Exh. BSG/Rebuttal-4, p.16. This additional analysis indicated that an Iowa 53-S2 life and curve was appropriate, which supports Mr. Robinson's use of the Iowa 55-S2 life and curve for plastic mains. Exh. BSG/Rebuttal-4, p. 16.

A review of the AGA-EEI industry depreciation survey indicates that the mean average service life for the overall industry Account 376 is 55 years and confirms Mr. Robinson's recommended service life for Bay State's Account 376.4. Exh. BSG/Rebuttal-4, p. 17. Various gas industry depreciation studies (and studies for selected gas companies in New England) demonstrate that average service lives of 55 years, and less, were routinely indicated for plastic distribution mains. Exh. BSG/Rebuttal-4, p. 17, at Exh. EMR-R3.

b. Account 376.2, Coated/Wrapped Steel Mains

Mr. Pous also recommended the use of the Iowa 74-R4 life and curve for Account 376.2 - Coated/Wrapped Steel Mains, in lieu of Mr. Robinson's estimated Iowa 55-R4 life and curve. Exh. AG-6, p. 41.

Mr. Robinson demonstrated that Mr. Pous simply misinterpreted the historical data and the likely impact of future activity on the average service life that can be achieved by this property category. Mr. Pous' misinterpretation is demonstrated in his statement that no significant weight should have been given to the retirement data points beyond 53 years of age because they were too small to clearly represent the anticipated future service life parameter for this property category. Exh. AG-6, pp. 36-37. Mr. Pous, however, failed to consider the fact that the oldest existing vintage investment in this property category is 1953 (which is fifty years of age as of the study date). Exh. BSG/Rebuttal-4, p. 18. Since the oldest vintage of surviving coated/wrapped steel mains is 1953, future retirements cannot occur at ages greater than 50. Exh. BSG/Rebuttal-4, p. 18. The occurrence of these retirements will automatically serve to either drive down the achieved average service life and/or, if all the retirements occur at the maximum possible age (which is unlikely given past experience), the resulting average service life for the account cannot be greater than 50 years. Exh. BSG/Rebuttal-4, p. 18. Mr. Pous' failure to recognize this demonstrates that he simply did not perform the kind of detailed analysis of the data that should have been performed. Exh. BSG/Rebuttal-4, p. 18.

The depreciation parameters for Account 376.2 - Coated/Wrapped Steel Mains set forth in Bay State's depreciation study are amply supported by the historical data and are appropriate for this property group. Exh. BSG/Rebuttal-4, p. 18. Moreover, in the gas industry depreciation data presented by Mr. Robinson for this account, numerous companies experienced service lives shorter than the 55 year average service life recommended by Bay State for Account 376.2. Exh. BSG/Rebuttal-4, pp. 18-19.

4. Use of Judgment

The Attorney General criticizes Mr. Robinson's use of judgment in his depreciation study. AG Br., at 64-65. The Department has long recognized that the use of judgment is essential in any depreciation study and that appropriate depreciation rates cannot be determined simply based on a statistical analysis of historic data. The Department has specifically noted that net salvage values are not to be determined statistically but are determined qualitatively, after taking into account both disposal historical experience and projected cost trends. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 134. Mr. Robinson has more than 30 years of experience preparing depreciation studies and has recommended depreciation rates based on that experience and his judgment after reviewing all of the factors influencing the Company's retirement of its plant in service. The Attorney General's claims on this subject should be given no weight by the Department.

IX. COST STUDIES

Bay State presented three cost studies to be used for cost allocation and rate design purposes. They are the proposed Simplified Market Based Allocation ("SMBA") method for gas costs, the Allocated Cost of Service Study and the Marginal Cost Study. The studies were prepared by James L. Harrison, Managing Consultant and Vice President of Management Applications Consulting, Inc.

A. Simplified Market Based Allocation (SMBA) Method for Gas Cost Allocation

Bay State has proposed the Simplified Market Based Allocation, or SMBA, method for gas cost allocation in this proceeding as well as for use in subsequent Cost of Gas Adjustment Clause ("CGAC") filings by Bay State. Exh. BSG/JLH-1, pp. 1-2. The SMBA simplifies and improves on the Market Based Allocation ("MBA") method that has been used by the Company since January 1996 pursuant to D.P.U. 95-52/104. The SMBA method and the differences between it and the MBA method are explained in the testimony of James L. Harrison. Exh. BSG/JLH-1.

The MBA method was first developed for Bay State in the Company's rate redesign proceeding, D.P.U. 95-52; Tr., at 651. In general, it was intended to recognize the differences in gas costs incurred to serve a customer with a high load factor versus a customer with a low load factor. Exh. BSG/JLH-1, p. 5; Tr., at 652. The MBA model is relatively complex and requires a substantial number of calculations. As a result, it requires a sizeable commitment of resources to prepare each of the Company's CGAC filings. Exh. BSG/JLH-1, pp. 6-7.

The Company has proposed to use the SMBA model, because it is administratively simpler than the MBA model and it produces results very similar to the MBA method. Tr., at 656-58.

The SMBA uses a design day allocator instead of the proportional responsibility weighted design year daily allocator used in the MBA. Tr., at 652. This makes the SMBA consistent with the Department's mandatory capacity assignment methodology set forth in D.T.E. 98-32 where the Department determined that capacity assignment should be based on class design day demands. Exh. BSG/JLH-1, p. 7. If the SMBA is used, the method for allocating capacity costs in Bay State's CGAC filings will be the same as the method used when capacity is assigned to migrating customers. Id., pp. 7-8. Therefore, migrating customers will be assigned the same capacity costs for which they were paying under the CGAC. Id., p. 8. With this change, Bay State's remaining sales customers will be neither benefited nor harmed as a result of customer migration to transportation service. Exh. BSG/JLH-1, pp. 7-8.

The major efficiency gained by use of the SMBA would be that the detailed design year daily allocations used in the more complex MBA are streamlined so that costs are allocated monthly rather than daily. Exh. BSG/JLH-1, p. 11. In addition, the requirement under the MBA that there be an individual dispatch of the MBA model for every supply source would be eliminated. Tr., at 653. The SMBA is a less complex model requiring fewer calculations for the CGAC filings. Tr., at 657. Exh. DTE-19-26 illustrates some of the differences between the SMBA and the MBA. Tr., at 657-58. In Berkshire Gas Company, D.T.E. 01-56, at 28, and

Fitchburg Gas and Electric Company, D.T.E. 02-24/25, at 249-50, the SMBA method was accepted by the Department. Tr., at 659.

The SMBA proposed by Bay State is virtually identical to the SMBA approved by the Department for Fitchburg Gas and Electric Light Company in D.T.E. 02-24/25, with one exception. Since Bay State's gas supply planning incorporates all supplies, including those independently contracted for by non-grandfathered transportation customers, Mr. Harrison has excluded the dispatched cost to serve non-grandfathered transportation customers in order to remove these costs from the firm sales customers' gas cost allocations. Exh. BSG/JLH-1, p. 13. In practice, the supply costs for non-grandfathered transportation customers are not incurred by Bay State but are assigned to marketers, and therefore Mr. Harrison has excluded them from the SMBA model. Exh. BSG/JLH-1, pp. 12-13.

Use of the SMBA requires no general conceptual changes to the CGAC, however Mr. Harrison proposed one simplification. Bay State's current CGAC establishes gas prices for nine different load factor based rates each season depending on rate class. Id., p. 20. In this proceeding, Mr. Harrison has proposed that the CGAC be revised to reflect one rate for all high load factor customer classes and a second rate for all low load factor customer classes. The costs to serve the high load factor classes are all quite similar as are the costs to serve the low load factor classes, and, therefore, two prices should be sufficient to convey the necessary price signals to customers and will eliminate the time and effort required to produce separate CGAC prices for each rate schedule. Exh. BSG/JLH-1, pp. 20-21. This is the method currently used by Berkshire Gas Company and Fitchburg Gas and Electric Light Company.

Bay State prepared a CGAC filing using the SMBA method for the period November 1, 2004 to October 31, 2005 to be consistent with the Company's CGAC filing of September 14, 2004 for the same period. Id., p. 18. This provides a direct comparison of the SMBA and MBA methods. Exh. BSG/JLH-1, p. 18; Exh. BSG/JLH-1, Sch. JLH-1-4. The Company requests approval to employ the SMBA method in all subsequent CGAC filings.

B. Allocated Cost of Service Study

Costs can vary significantly between customer classes depending on the nature of the loads on a company's system imposed by those classes and the facilities available to serve those classes. Exh. BSG/JLH-2, p. 3. The purpose of an Allocated Cost of Service Study is to assign or allocate each relevant cost component of a company on an appropriate basis in order to determine the proper cost to serve the respective classes. Exh. BSG/JLH-2, p. 3. Mr. Harrison's Allocated Cost of Service Study analyzed each element of Bay State's rate base and operations and maintenance expenses and allocated those costs to customer classes. Id., pp. 7-17. His study is fully explained in Exh. BSG/JLH-2 and summarized in Schedule JLH-2-1. It mirrors Bay State's total cost of service presented by Mr. Skirtich and is summarized in the reconciliation schedule in Schedule JLH-2-1. Exh. BSG/JLH-2, p. 4.

The results of the study demonstrate that the rates currently in effect generate slightly different rates of return for each customer class, producing some inequities among rate classes. Id., p. 18. However, with the exception of the residential non-heating class, the differences are minor. Id. As expected, the residential low-income classes generate lower rates of return. Id.

In addition, the study identifies the lower rates of return produced by the small low winter use commercial and industrial customers served under rates G-50 and T-50. Id., p. 19.

Mr. Harrison's Allocated Cost of Service Study also identifies costs by function, such as supply and delivery, and provides information with respect to the unbundled costs to serve. Exh. BSG/JLH-2, pp. 19-21. The study provides the information needed to update the Company's CGAC by segregating five gas supply costs from delivery revenue requirements. Id., p. 21. These supply costs are: (1) the costs of the Company's manufactured gas facilities, (2) working capital associated with gas costs, (3) operations and maintenance expenses associated with gas acquisition and dispatching costs, (4) uncollectible expense recorded in account 904, and (5) overhead costs, including general plant and administrative and general expenses. Exh. BSG/JLH-2, pp. 21-24.

1. The Attorney General's Arguments Regarding Energy Products and Services ("EP&S")

a. The Attorney General's Proposal to Assign EP&S Revenues Directly to the Residential Class

Bay State operates an energy products and services ("EP&S") business that is integrated into its gas utility business. Exh. BSG/SHB-1, p. 51. The EP&S business includes the Guardian Care service (service for customer-owned gas equipment), water heater and conversion burner rentals, annual inspections of customer heating systems, providing customers with heating equipment and water heater repairs on a fee for service basis and boiler and furnace installations. Exh. BSG/SHB-1, p. 52. With the exception of boiler and furnace installations, all of the EP&S

businesses are treated above the line for ratemaking purposes, which means both the revenues and expenses are included in rates. Exh. BSG/SHB-1, pp. 55-58. Since EP&S revenues exceed costs, the EP&S business profits in the test year reduce the required revenue deficiency in this proceeding. Exh. BSG/SHB-1, p. 58; Exh. MOC-4-2.

The Attorney General argues that since most of the EP&S revenues are generated by residential customers, EP&S revenues and related costs and margins should be directly assigned to the residential classes. AG Br., at 73. The Attorney General proposes this because the large majority of EP&S customers are residential customers. He notes that the Allocated Cost of Service Study employs a distribution plant allocator for all EP&S revenues and costs, which assigns approximately 55% of the EP&S margins to the residential classes. AG Br., at 73.

This argument ignores basic cost allocation principles and assumes that costs should be attributable to a particular class based on the revenues generated by that class. This approach does not follow proper cost allocation principals. Boston Gas Company, D.T.E. 03-40, at 367 (2003). The Allocated Cost of Service Study recognizes that EP&S revenues are an opportunity created by the existence of facilities and resources available on the Company's distribution system. Therefore, the study allocates all EP&S revenues and costs to each of the Company's rate classes based on the DISTR allocation factor, the same distribution demand allocator used to allocate distribution plant. Exh. BSG/JLH-2, pp. 7-8, Sch. JLH-2-2 and Sch. JLH-2-3. This allocator properly allocates approximately 55% of the margins from the EP&S businesses to the residential class. Exh. BSG/JLH-2, Sch. JLH-2-2.

If the Attorney General's logic were to prevail, that cost causation and allocation should be based on revenue generation, then the cost study's allocation of interruptible sales margins would be inappropriate, since the revenues from this service are provided by commercial and industrial customers. Under the Attorney General's proposal, all interruptible margins would be assigned to commercial and industrial customers, and the residential class would not receive any benefits from interruptible sales margins. AG Br., at 73. It is not the Department's policy to allocate costs based on the revenues generated by a particular rate class. Both the interruptible and EP&S margins are the result of opportunity sales available from the resources utilized for the benefit of firm customers. Exh. BSG/SHB-1, p. 53. In the case of the distribution system, the cost study assigns the costs of these resources to firm customers using the DISTR allocation factor. Exh. BSG/JLH-2, p. 8. It is only logical that the benefits from those resources, including the EP&S margins, should flow back to the customers who paid for the resources by use of the same allocator. This is consistent with the Department's treatment of above-the-line service businesses. Bay State Gas Company, D.P.U. 92-111 (1992). Margins generated by these incremental programs benefit all of the Company's firm customers by permitting the Company's fixed costs to be spread over a larger revenue base.

The Attorney General's proposal to directly assign EP&S revenues to the residential classes should be denied.

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C. Marginal Cost Study

Mr. Harrison prepared a marginal cost study which provides certain cost data used by Mr. Ferro in his proposed rate design. Exh. BSG/JLH-3, p. 1.

The purpose of a marginal cost study is to provide an estimate of the costs of providing an additional unit of service. Exh. BSG/JLH-3, p. 2. These estimates may be used as a threshold in establishing pricing levels for special contracts and for value of service pricing. Exh. BSG/JLH-3, p. 2. More importantly, the Department has determined in many proceedings that the use of marginal costs in ratemaking will result in a level and pattern of prices that promotes appropriate consumption decisions and efficient allocation of society's resources. Exh. BSG/JLH-3, pp. 2-3. This efficiency is promoted when customers have accurate price signals regarding the costs of their consumption decisions. Exh. BSG/JLH-3, p. 3. As a result, customers will be able to make more informed decisions on their use of gas service. Exh. BSG/JLH-3, p. 3.

In Mr. Harrison's study, the marginal commodity cost is intended to reflect the short run variable costs of the Company's gas sendout. Exh. BSG/JLH-3, p. 3. The marginal production capacity cost is intended to reflect the long-run costs of expanding production facilities to meet an increase in customer requirements for gas service. Exh. BSG/JLH-3, p. 3. The marginal distribution cost is intended to reflect the cost, based on historical data and recent trends, of expanding the local distribution network to accommodate customer growth. Exh. BSG/JLH-3, p. 3. Mr. Harrison computed the marginal costs to serve each of Bay State's rate classes based on forward looking rate year costs. Exh. BSG/JLH-3, p. 3.

For commodity costs Mr. Harrison has used the futures costs of gas (NYNEX) and adjusted these for the cost basis at Bay State's city gates to determine the daily costs of serving a small increment of customer load. Exh. BSG/JLH-3, p. 3. He employed the peaker method to estimate production capacity costs. Exh. BSG/JLH-3, p. 3. He used regression and engineering techniques to estimate the hypothetical distribution costs of serving an increment of customer load including the unit costs of adding distribution plant facilities as well as the additional costs for operations and maintenance expense. Exh. BSG/JLH-3, pp. 3-4. He used engineering estimates to identify the investment in services and meters and added operations and maintenance expenses necessary to service a new customer. Exh. BSG/JLH-3, p. 4. From these costs, he determined the annual requirement to serve each of Bay State's rate classes in terms of customer commodity and demand charges. Exh. BSG/JLH-3, p. 4.

Mr. Harrison carefully reviewed the Department's directives concerning the use of econometric methods in the preparation of marginal cost studies in the recent Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25 and Boston Gas Company, D.T.E. 03-40, orders and made every effort to comply with those directives within the limitations of the data available to him. Mr. Harrison provided a thorough explanation of how he complied with those directives and where, in certain cases, it was either not possible or practical to comply with all of those directives or when he used non-econometric methods, such as engineering methods, to estimate marginal costs, in which case the directives were not applicable. See Exhs. DTE-2-1 through DTE-2-8; Exhs. DTE-15-5 through DTE-15-16.

X. PERFORMANCE BASED REGULATION

A. Introduction

Bay State has proposed a performance based regulation ("PBR") plan that is consistent with sound economic principals and the Department's PBR standards. The proposed PBR plan will create incentives for Bay State to continue to perform efficiently and to provide high quality service for its customers. Exh. BSG/LRK-1, p. 2.

Bay State has proposed a PBR plan that is as consistent as possible with Department's 2003 order on the PBR plan of Boston Gas Company in D.T.E. 03-40. To reduce the time and expense necessary to review its PBR proposal, Bay State has relied on the productivity study recently approved by the Department in D.T.E. 03-40 and proposed a productivity factor (the X factor) of 0.41%, identical to what the Department approved in that case. This includes a consumer dividend of 0.3%, identical to the consumer dividend approved in D.T.E. 03-40. Bay State today has fewer opportunities to improve its productivity performance than did Boston Gas at the time of D.T.E. 03-40, and, therefore, Bay State's consumer dividend should be no greater than what was approved for Boston Gas in D.T.E. 03-40.

This is the first index-based PBR proposed by Bay State, and, therefore, it has proposed a five-year term for the plan, which is consistent with Department precedent for initial index-based PBR plans. The other significant elements of Bay State's PBR proposal have also been designed to be consistent with the PBR plan the Department approved in D.T.E. 03-40. Exh. BSG/LRK-1, pp. 18-19.

Bay State's PBR proposal was developed by Dr. Lawrence R. Kaufmann, a partner at Pacific Economics Group LLC and a nationally recognized expert on PBR plans. Dr. Kaufmann has designed PBR plans for numerous utilities. He developed the PBR plan for Boston Gas Company in D.T.E. 03-40 and co-authored a report on service quality PBR in Massachusetts for the D.T.E. 99-84 proceeding on establishing service quality standards for gas and electric distribution utilities. In addition to Massachusetts, he has filed testimony on PBR issues in Rhode Island, Kansas, Hawaii, Oklahoma, and Kentucky and has co-authored reports on PBR issues in California and British Columbia. He has testified on PBR issues in Australia and New Zealand and recently prepared a report for the Ontario Energy Board on PBR issues in Canada. Exh. BSG/LRK-1, pp. 1-2; RR-DTE-26.

B. The Price Cap Formula

Bay State is proposing an index-based PBR where the maximum change in its rates will be limited by a price cap index ("PCI") formula. PCI establishes a maximum annual adjustment in base rates on the basis of inflation and a productivity factor offset, as well as any qualifying exogenous cost changes approved by the Department. Bay State has proposed a price cap formula identical to that approved by the Department in D.T.E. 03-40 as follows:

$$PCI_t / PCI_{t-1} - 1 = \left(P_t / P_{t-1} - 1 \right) - X + Z_t .$$

Exh. BSG/LRK-1, p. 3. The P_t term is an inflation factor. X is the productivity factor offset (or X factor) and Z_t is the exogenous cost factor (or Z factor) which recovers the expenses of certain exogenous costs that must be approved by the Department that effect the Company's unit costs but are not accounted for in the inflation or the X factor. Exh. BSG/LRK-1, p. 3; Exh. DTE-4-51.

1. Inflation Measure

The inflation measure proposed is the annual growth in the Gross Domestic Product Price Index ("GDP-PI"). The GDP-PI is an official measure of price inflation in the U.S. economy. It is considered to be a more accurate and more stable measure of economy wide inflation than other broad inflation measures such as the Consumer Price Index. Boston Gas Company, D.T.E. 03-40, at 473. The GDP-PI is readily available and has been used by the Department in approving the rate indexing or PBR plans for Boston Gas Company, Berkshire Gas Company and Blackstone Gas Company. Exh. BSG/LRK-1, p. 8.

2. X-Factor

Bay State has proposed a productivity or X factor represented by the formula that is identical to what the Department approved in D.T.E. 03-40:

$$X = \left(TFP^{IND} - TFP^{US}\right) + \left(W^{US} - W^{IND}\right) + CD$$

Exh. BSG/LRK-1, pp. 3-4.

In this formula, TFP^{IND} represents the total factor productivity ("TFP") trend for the gas distribution industry, TFP^{US} represents the TFP trend for the US economy, W^{IND} is the input price trend for the gas distribution industry, W^{US} is the input price trend for the US economy, and CD is the consumer dividend. TFP growth is defined as the change in the total output supplied minus the change in inputs used to produce output. TPF^{IND} is therefore a measure of the change in productive efficiency for the gas industry, and TFP^{US} is a measure of the change in productive efficiency for the US economy. The difference ($TFP^{IND} – TFP^{US}$) is referred to as the productivity differential. Input price growth refers to inflation in the prices paid for the inputs used in production. The difference ($W^{US} – W^{IND}$) is referred to as the inflation differential. Therefore the proposed X factor is the sum of three components: the productivity differential, the inflation differential, and the consumer dividend. The CD term reflects the expectation of Bay State's incremental productivity gains under the PBR. Exh. BSG/LRK-1, pp. 4, 6. The Department has used this X factor formula in other rate indexing and PBR plans for Massachusetts gas utilities. Exh. BSG/LRK-1, pp. 6-7.

The proposed X factor value in Bay State's PBR plan is 0.41%. This represents the sum of the productivity and inflation differential components of the formula (0.11%) and the consumer dividend (0.3%). It is identical to the X factor approved by the Department in D.T.E. 03-40.

There are a number of reasons why the values for the components of the X factor approved in D.T.E. 03-40 are appropriate for use for Bay State in this proceeding. First, the D.T.E. 03-40 order was issued less than two years ago. Therefore, the 0.11% value determined then, as the sum of the productivity and inflation differentials, is still current. Second, the values for the productivity and inflation differentials approved in D.T.E. 03-40 were based on a regional definition of the gas distribution industry that is directly applicable to Bay State, which operates in the same industry and same region as Boston Gas Company. Third, the Department approved the 0.11% value after an extensive review and analysis in D.T.E. 03-40 of studies performed by Dr. Kaufmann on industry productivity and input price trends. There would have been little additional benefit, and a substantial additional cost, of repeating that analysis in this proceeding. Fourth, the Department has permitted other gas companies in Massachusetts to use productivity offsets that were approved for Boston Gas Company. The rationale for this approach has been that the productivity offset approved for Boston Gas Company is not necessarily unique to any specific gas company since it was based on a sample of many local gas distribution companies. In addition, if another productivity study were undertaken, the results would likely be similar to what they were in the study presented in the Boston Gas Company case.

Finally, the Department has indicated that the cost of an additional productivity study can outweigh the benefits of such a study in terms of any improved accuracy of the TFP trend. Berkshire Gas Company, D.T.E. 01-56, at 21 (2001). Because Bay State's productivity offset is both more accurate and more current than what the Department approved for Berkshire Gas, the Department's conclusion in D.T.E. 01-56, that the costs of updating the productivity offset outweigh the potential benefits, is also true for Bay State's current proposal. Exh. BSG/LRK-1, pp. 9-10.

3. Consumer Dividend

The consumer dividend has been defined by the Department as a future productivity factor designed to reflect future productivity gains related to the move from cost of service regulation to PBR. Exh. BSG/LRK-1, pp. 10-11. Bay State has proposed a consumer dividend in this proceeding of 0.3%, the value developed and approved in D.T.E. 03-40. The level of the

D.T.E. 03-40 consumer dividend was, in part, based on the fact that Boston Gas had achieved efficiency gains in its initial PBR plan approved in D.P.U. 96-50, and that there was less opportunity for further efficiency gains in the PBR plan proposed in D.T.E. 03-40. Exh. BSG/LRK-1, pp. 10-11.

The consumer dividend approved in D.T.E. 03-40 is appropriate for use by Bay State in this proceeding because, like Boston Gas in D.T.E. 03-40, Bay State in this case is effectively updating a type of performance based regulation plan, and Bay State's cost performance under its previous plan indicates that it has less potential to achieve further efficiency gains than Boston Gas did at the time D.T.E. 03-40 was approved. Bay State was subject to a five-year rate freeze between 1999 and 2004. An extended rate freeze such as this creates performance incentives that are very similar to a rate indexing PBR plan, since rate freezes create incentives for utility management to pursue efficiency gains. Bay State is filing its PBR plan at the expiration of that rate freeze. It is therefore appropriate to examine Bay State's cost performance over the term of its expired plan to determine the Company's opportunity to achieve further efficiency gains, as the Department did for Boston Gas in D.T.E. 03-40. Exh. BSG/LRK-1, p. 11-12.

Dr. Kaufmann conducted two separate empirical analyses of Bay State's cost performance under its rate freeze to determine whether a 0.3% consumer dividend is appropriate. The first was a comparison of Bay State's operations and maintenance ("O&M") cost trends before and after the rate freeze. The second analysis was a statistical benchmarking study that evaluated Bay State's O&M cost performance over the five years of the rate freeze relative to the

U.S. gas distribution industry. These analyses were submitted in a report entitled "O&M Cost Analysis for Bay State Gas Company." Exh. BSG/LRK-2; Exh. DTE-4-23; Exh. DTE-4-24, 4-25.

The O&M cost trend analysis showed that for the five years before the rate freeze took effect in 1999, Bay State's O&M costs increased by an average of 3.9% per year in real terms. During the rate freeze (1998-2003) the Company's O&M costs declined by an average of 2.2% per year in real terms. The difference between the Company's growth in O&M costs before and after the rate freeze took effect was 6.1% per year. This analysis shows that Bay State responded to the incentives of the rate freeze by improving its O&M cost efficiency. This improvement in O&M cost efficiency was more than four times greater than the comparable decline of 1.3% experienced by Boston Gas Company during its first PBR plan, which the Department referenced when approving a 0.3% consumer dividend in D.T.E. 03-40. Exh. BSG/LRK-1, pp. 12-13; Exh. DTE-4-27.

Dr. Kaufmann also undertook an econometric evaluation of the Company's O&M costs over the rate freeze period. This evaluation developed an econometric cost model that predicted the O&M costs of gas distribution services in light of various factors beyond a utility's control. The model estimated the impacts of these various factors on a gas distribution company's expected O&M costs using a national sample of gas distribution company data. The actual values of these factors for Bay State were then inserted into the estimated econometric model to develop a prediction for Bay State's O&M costs. Bay State's actual O&M costs were then compared to the predicted costs for Bay State to evaluate its O&M cost efficiency.

This study was similar to the econometric benchmarking study that Dr. Kaufmann performed for Boston Gas Company in D.T.E. 03-40. However, the benchmarking study in this proceeding was modified to respond to certain concerns the Department expressed regarding the Boston Gas study. In particular, Dr. Kaufmann here focused his study on O&M costs rather than on total costs (O&M plus capital costs) to reduce the concerns the Department had expressed in D.T.E. 03-40 with regard to capital vintaging and the effects that asset age may have on gas distribution costs. However, in the Bay State study, Dr. Kaufmann did include a system age variable to control directly for system age effects on O&M costs. Exh. BSG/LRK-1, pp. 13-14; Exh. DTE-4-7.

The results of the benchmarking study found that Bay State's O&M costs were 14.4% <u>below</u> their predicted value during the rate freeze period. The difference between Bay State's actual and predicted O&M costs was also found to be statistically significant. Therefore, Dr. Kaufmann concluded that Bay State is a significantly superior O&M cost performer within the U.S. gas distribution industry. Exh. BSG/LRK-1, p. 14; Tr., 1427-28.

Dr. Kaufmann's analysis indicates that the consumer dividend for Bay State should be <u>no greater</u> than 0.3%. The Department approved a 0.3% consumer dividend for Boston Gas in D.T.E. 03-40, and the evidence in this proceeding shows that Bay State has responded more strongly to the incentives created by its rate freeze than did Boston Gas to its first PBR plan. This indicates that Bay State has fewer opportunities than Boston Gas did at the time D.T.E. 03-40 was issued to achieve further productivity gains in the future, so Bay State's consumer dividend should be no higher than that which was approved for Boston Gas Company. Exh. BSG/LRK-1, p. 15; Exh. DTE-4-27.

4. <u>Proposed Z Factor</u>

Bay State has proposed a Z factor consistent with the Department's definition of exogenous costs. Exh. BSG/LRK-1, p. 15. The Z factor would recover exogenous costs not reflected in the inflation and productivity differential components of the X factor. Exh. BSG/LRK-1, p. 15. Exogenous costs are defined as (1) changes in tax laws, accounting principles, and regulatory, judicial or legislative actions uniquely affecting the local gas distribution industry, and (2) cost changes that are beyond the Company's control and not accounted for in the GDP-PI term used in the PBR formula. Tr., at 679, 751-52; Exh. BSG/JAF-1, p. 28; Exh. BSG/LRK-1, p. 15; Exh. BSG/JAF-2. Only costs exceeding a materiality threshold of $600,000 for the rate year would be able to be reflected in the Z factor, and only after approval by the Department. Exh. BSG/JAF-2, p. 29.

C. Term of the PBR Plan

Bay State has proposed a five-year PBR plan. Exh. BSG/LRK-1, p. 7. A five-year term balances two important considerations: 1) the term should be long enough to create meaningful performance incentives for Bay State, and 2) the plan must be short enough so that indexed based prices do not become unrepresentative of the general conditions in the economy or the experience of the natural gas industry. Exh. BSG/LRK-1, p. 7.

A five-year plan is consistent with the Department's precedent for gas distribution companies that are proposing rate indexing PBR plans for the first time, which is the case with Bay State in this proceeding. Exh. BSG/LRK-1, p. 7. The initial PBR term approved for Boston Gas was five years. D.P.U. 96-50; Exh. BSG/LRK-1, p. 7. The most recent rate indexing plan approved for a Massachusetts gas company was a five-year plan approved for Blackstone Gas Company in the D.T.E. 04-79 proceeding. See also Exh. BSG/LRK-1, p. 7. Although the Department has approved 10-year PBR terms, these have applied to updated rate indexing PBR plans (Boston Gas Company in D.T.E. 03-40) or a combined rate freeze rate/indexing plan where the rate indexing period was less than 10 years. Berkshire Gas Company, D.T.E 01-56, at 77. The most common period for a rate indexing or PBR plan in North America and throughout the world is five years, and PBR plan terms of 10 years are rare outside of Massachusetts. Exh. BSG/LRK-1, pp. 7-8; Tr., at 687-88; Tr., at 729.

D. Earnings Sharing Mechanism

Bay State has proposed an earning sharing mechanism ("ESM") identical to the one approved in the original PBR plan for Boston Gas Company and also in the recent Boston Gas proceeding, D.T.E. 03-40. Tr., at 1437. The mechanism has a 400 basis point deadband above and below the allowed return on equity ("ROE"), where there is no earnings sharing. Exh. BSG/LRK-1, p. 18. Above or below that deadband, any excess or shortfall in earnings is shared 75% to shareholders and 25% to customers. Exh. BSG/LRK-1, pp. 17-18.

Earnings of the Company in each rate year will be compared with the allowed ROE. Exh. BSG/LRK-1, pp. 17-18; Tr., at 1440. If the actual earnings are within the 400 basis points band above or below the allowed ROE, no earnings would be shared. Exh. BSG/LRK-1, pp. 17-18; Exh. BSG/JAF-2, p. 29; Tr., at 1437. If earnings exceed the allowed ROE by more than 400 basis points, 25 percent of the value of the earnings in excess of the band would be returned to customers by means of an additional adjustment incorporated in the PCI formula for the next rate year. Exh. BSG/LRK-1, p. 18; Exh. BSG/JAF-2, p. 29; Tr., at 1440. Similarly, if the ROE in a year should fall below the allowed level by more than 400 basis points, 75 percent of the value of the shortfall below the band would be absorbed by shareholders, and 25 percent recovered from customers, through an upward adjustment of the PCI rate cap. Exh. BSG/JAF-2, p. 29; Tr., at 1440. Any earnings-related adjustment resulting in increased rates would be subject to the overall PBR limits on rate and rate element increases.

There are two purposes of the ESM. One is to allow customers to share in the benefits of efficiency gains made by Bay State under the PBR plan. Tr., at 1441-42. The second is to provide a symmetrical mitigation of the risks, to both customers and shareholders, of a significant deviation in the earned ROE either above or below authorized levels during a particular rate year. Exh. BSG/JAF-2, p. 29; Tr., at 1441-42, 1448.

Although the Company initially proposed a 400 basis point earnings sharing deadband to be consistent with the D.T.E. 03-40 precedent, Dr. Kaufmann indicated during the hearings that Bay State would accept a 200 basis point earnings sharing deadband, as well as a sharing outside of the band of 50% to shareholders and 50% to customers. Tr., at 1444-45; Exh. BSG/Rebuttal-5, p. 9-11.

E. Service Quality

Bay State's PBR proposal does not change in any way the service quality standards applicable to the Company. Exh. BSG/LRK-1, p. 18; AG. Br., at 121; UWUA Br., at 36; DOER Br., at 4.

F. Price and Rate Design Flexibility

The Company's prices under the PBR Plan will comply with the index-based limitations on prices in two ways. Exh. BSG/LRK-1, p. 16. First, the Company's index-based price change in each year will not exceed the growth in the PCI (i.e. GDP-PI inflation minus 0.41%, plus or minus any Z factor) in that year. Second, in any given year no individual rate element within a rate class will increase more rapidly than the inflation in the GDP-PI or the PCI, which ever is highest. Exh. BSG/LRK-1, p. 16. The Company will compute an average rate of price change using information on its individual rate elements. Exh. BSG/LRK-1, p. 16. In each year, the inflation in each rate element will be weighted by its share of the Company's total regulated revenue for that rate class in the previous year. Exh. BSG/LRK-1, p. 16. The Company's overall rate adjustment will be calculated as a weighted average of the price changes for the individual rate elements. Exh. BSG/LRK-1, p. 16.

This approach gives the Company a measure of flexibility in pricing while insuring that no rate element can increase more rapidly than GDP-PI inflation or PCI. Exh. BSG/LRK-1, p. 16. This is identical to the method the Department approved for Boston Gas Company's PBR Plan in D.T.E. 03-40. Exh. BSG/LRK-1 pp. 16-17; Tr., at 1480-81.

G. Compliance

On or before June 1, 2006, and annually thereafter through 2009, the Company will submit a tariff filing containing proposed revised tariff sheets to implement rate changes pursuant to the Annual Base Rate Adjustment Mechanism ("ABRAM") described in the testimony of Mr. Ferro. Exh. BSG/JAF-2, p. 33. With the ABRAM, base rates will be adjusted for three distinct categories[50] of changes, one of which is the PBR adjustment.

H. Relationship Between the Company's PBR Proposal and the Steel Infrastructure Replacement ("SIR") Program

The Company has proposed a steel infrastructure replacement ("SIR") program and cost recovery mechanism through the ABRAM designed to help the Company recover the costs of achieving the public safety and system reliability obligations associated with the SIR program as described in the testimony of Mr. Bryant and others in this proceeding. Exh. BSG/SHB-1, pp. 40-41; Exh. BSG/JAF-2, pp. 23-28, Sch. 2-9; Tr., at 2195, 3864 and 3895. The SIR program is required by the severe and accelerating leak problem on Bay State's bare and unprotected steel infrastructure. Exh. BSG/SHB-1, p. 37; Tr., at 677-712, 3319. As Mr. Bryant has indicated, the Company must replace its bare and unprotected steel infrastructure regardless of whether the proposed SIR cost recovery mechanism is approved. Exh. BSG/Rebuttal-5, p. 7. However, Mr. Bryant and the Company's witness on rate of return, Mr. Moul, have indicated that in the

[50] As described in Mr. Ferro's testimony, the ABRAM would adjust rates annually after the first rate year to reflect cost savings associated with energy efficiency programs implemented by the Company, and to recover revenue requirements associated with the proposed SIR program, as well as to implement PBR rate adjustments. Exh. BSG/JAF-2, pp. 23-24. The SIR and energy savings components of the ABRAM are addressed elsewhere in this Brief.

absence of the SIR rate recovery program, the Company will not have a reasonable opportunity to recover the incremental investment costs of the SIR program and earn its allowed rate of return. Exh. BSG/PRM-1, pp. 10-13. Therefore, it will be required to file base rate proceedings to recover the capital costs of the SIR program. Exh. BSG/Rebuttal-5, p. 7.

Furthermore, the PBR price cap index will not accommodate the rapidly increasing capital expenditures of the SIR program, because the price cap index is based on past industry trends and the capital requirements of the SIR program are not reflected in that industry experience. Tr., at 675-78. In situations such as this, a separate targeted rate recovery mechanism, outside of the PBR price cap index, is appropriate and consistent with PBR theory. Tr., at 680-81. For example, in Victoria, Australia utilities were required to invest a large amount of capital over a relatively short period of time to replace all of their existing meters with interval meters. Tr., at 679-81. This intensive capital investment program was not reflected in the past capital spending experience of the companies involved, and therefore an adjustment of the companies' PBR was implemented to recover the costs of the new meters. Tr., at 679-81.

Here, Bay State proposes that the index-based pricing changes of the PCI be completely independent of the SIR rate recovery mechanism in the ABRAM. Exh. BSG/LRK-1, p. 17. The PCI will apply only to the portion of Bay State's cast off rates that <u>exclude</u> all costs associated with the eligible facilities that are part of the SIR program. Therefore, the PCI and the SIR rate adjustment mechanisms apply to completely different sets of costs and operate independently of each other. Exh. BSG/LRK-1, p. 17; Tr., at 684.

It is Dr. Kaufmann's opinion that customers will benefit if the costs of the SIR program are recovered through the ABRAM as proposed by Bay State rather than in base rate proceedings. The benefits of the proposed SIR rate recovery are lowered procurement costs for the replacement of steel mains and lower regulatory costs, both of which are goals of a PBR plan. Exh. BSG/Rebuttal-5, p. 7.

In contrast, the Company will incur higher overall regulatory and administrative costs if it is required to file new base rate cases to recover the costs of the SIR program. Exh. BSG/Rebuttal-5, pp. 6-7. The SIR rate recovery in the ABRAM will also produce gradual and relatively predictable rate increases. However, the filing of base rate cases by Bay State to recover its SIR costs will produce larger and more unexpected rate increases that will create rate shock for customers. Tr., at 682. Furthermore, O&M cost savings will be passed through to customers in the ABRAM immediately as they occur, rather than in the less frequent base rate proceedings that would be required if the SIR cost recovery mechanism is not approved. Tr., at 684. Under the SIR proposal, all SIR costs will be subject to Department review, and therefore there should be no concern that they will not be subject to appropriate regulatory scrutiny.

I. DOER's Testimony on Bay State's PBR Plan

The Massachusetts Division of Energy Resources ("DOER") commented on the Company's PBR proposal through the testimony of Alvaro E. Pereira, the Manager of Energy Supply and Pricing at the DOER. In Dr. Pereira's direct testimony, he supports the concept of a PBR, but believes that the Company has proposed a "partial PBR" that caps only a portion of its costs. Exh. DOER-1, p. 3. He apparently bases this conclusion, in part, on the fact that the SIR costs will not be subject to the PBR price cap mechanism. Id. Although he criticizes the Company for proposing a "partial PBR," he then goes on to recommend his own "partial PBR," which would apply the price cap index only to O&M costs. Exh. DOER-1, p. 7.

Although not contained in his pre-filed direct testimony, Dr. Pereira substantially changed his partial PBR proposal in his oral testimony to one involving two PBRs, or alternatively, one PBR with two different X factors, one that applies to Bay State's O&M costs and the other that applies to its capital costs, which in essence would constitute a rate freeze on capital costs. Exh. DOER-1, p. 4; Tr., at 2865. In fact, Dr. Pereira did not set forth all of the elements of his proposals until his oral surrebuttal testimony presented on the last day of evidentiary hearings in this case. Tr., at 3981-4010. The proposals presented in Dr. Pereira's oral surrebuttal testimony also differ from the summary of those proposals in the DOER's Initial Brief, particularly on the critical issue of whether DOER has, in fact, proposed a comprehensive PBR that applies to both capital and O&M costs. DOER Br., at 7.

Dr. Pereira does not question the need for the SIR program but recommends the rejection of the Company's SIR program cost recovery mechanism. Exh. DOER-1, p. 3; Tr., at 2884-85.

Finally, Dr. Pereira recommends a change to the Company's proposed earnings sharing mechanism to reflect "the relative riskless nature of gas distribution." Exh. DOER-1, p. 3. He proposes an earnings sharing mechanism whereby earnings in excess of the allowed ROE, within a band of 200 basis points above the allowed ROE, would all be returned to customers. Only after earnings exceeded the 200 basis point band would earnings be shared 75% with shareholders and 25% with customers. Earnings that fall below the allowed ROE are retained by the Company, but customers would not have to be charged for any deficiencies in earnings due to "riskless nature" of Bay State's SIR rate proposal. Exh. DOER-1, p. 9. In his surrebuttal testimony, Dr. Pereira changed this direct testimony to propose a band where all earnings would go to the Company up to 50 basis points above the allowed ROE. For earnings between 51 and 200 basis points above the allowed ROE, there would be a sharing 75% with customers and 25% with shareholders. For earnings above 200 basis points over the allowed ROE, earnings would be sharing 75% with shareholders and 25% with customers. DOER Br., at 10-11; Tr., at 3990-91.

J. Bay State's Rebuttal to the DOER's Testimony

In his rebuttal testimony and in responses to Department record requests, Dr. Kaufmann provided an extensive critique of Dr. Pereira's recommendations. He demonstrates that Dr. Pereira's recommendations are not well-founded, arbitrary, not based on sound theoretical analysis, and inconsistent with the Department's goals and standards for incentive regulation. Exh. BSG/Rebuttal-5; Exhs. RR-DTE-162, 163, 164, 165 and 170. Furthermore, Dr. Pereira has never testified on PBR before, and his testimony displays a misunderstanding of PBR, the Department's PBR precedents and the PBR evidence presented in this case. Tr., at 2856.

1. The DOER's Objection to the SIR Rate Recovery Mechanism is not Supported by the Record

Dr. Pereira objects to the SIR program rate recovery because it will "increase the level of uncertainty in future rate changes". Exh. DOER-1, p. 5, see also DOER Br., at 8. This conclusion does not take into account the uncertainty for customers that would be created by the series of base rate proceedings that would be required to recover the SIR program costs if the Company's SIR rate recovery mechanism is not approved. These additional base rate proceedings will lead to rate increases at unpredictable intervals, as well as increasing the total costs of the SIR program due to the higher regulatory and administrative costs that result from more frequent base rate proceedings. The SIR cost recovery proposal, however, will cause customer rates to change by relatively smaller and more predictable increments and at more frequent intervals, and therefore would avoid the rate shock of large rate increases resulting from base rate proceedings. The SIR cost recovery proposed will create greater certainty with respect to future rate changes, and not less as Dr. Pereira suggests. Exh. BSG/Rebuttal-5, pp. 7-8.

The SIR cost recovery program is compatible with the PBR incentives and will create benefits for customers, when compared with not having a SIR program. Tr., at 756-57. Contrary to the DOER's claim, the SIR is also compatible with traditional cost of service regulation. DOER Br., at 8; Tr., at 681-82. The SIR program costs will be monitored and reviewed by the Department in relatively straight-forward proceedings before any costs are approved for recovery in rates. Exh. BSG/SHB-1, pp. 41-42; Tr., at 259-60. The costs of such proceedings will be less than costs required for the base rate proceedings, and there will be a reduction in regulatory costs with the SIR cost recovery mechanism. It appears that the DOER has overstated the overall five-year estimated SIR rate increases by using the first year costs of $6 million in all five years for its estimate. DOER Br., at 8. The $6 million first year cost declines to $3.4 million in subsequent years of the program. Exh. BSG/JES-1, Sch. JES-17, line 17.

2. **<u>The DOER's Proposed Earnings Sharing Mechanism Would Create Minimal Incentives to Improve Efficiency</u>**

Dr. Pereira's original recommendation that customers receive 100% or even 75% of all earnings within a band above the allowed ROE would create minimal incentives for the Company and, in fact, discourage it from taking actions that could improve its efficiency. DOER Br., at 10-11; Tr., at 3990-91; Exh. BSG/LRK-1, pp. 17-18. For example, there are often cost saving initiatives that require upfront costs in the early years but which reduce costs in later years. If a cost saving project required an upfront investment and would produce 100 basis points of earnings in future years, a company would have no incentive to make the cost saving investment under Dr. Pereira's proposal. Under his proposal, a company would not choose to pursue such projects since doing so would reduce its earnings in the early years and the company would not be able to retain the benefits in later years. Dr. Kaufmann was not aware of any earnings sharing mechanism anywhere in the world where 100% of earnings immediately above the allowed ROE are returned to customers. Exh. BSG/Rebuttal-5, pp. 9-10. Dr. Pereira's revised proposal to allow the Company to retain earnings within a 50 basis point band around the ROE represents some improvement. Tr., at 3990-91.

The DOER states that the Company's originally proposed 400 basis point deadbound around the allowed ROE makes Bay State's earnings sharing mechanism ("ESM") "the most heavily tilted towards shareholders than any of the ESMs adopted by other jurisdictions surveyed by DOER." DOER Br., at 10. However, in Massachusetts, the PBR plan approved for Berkshire

Gas has no ESM, and therefore does not require shareholders to share any earnings with customers. Berkshire Gas Company, D.T.E. 01-56, at 7.

3. DOER's Two X-Factor Proposal Does Not Comply with the Department's PBR Standards

DOER presents a partial PBR proposal with two X-factors, because it believes that Bay State's plan is inconsistent with Department precedent. DOER apparently believes that a comprehensive PBR plan can only be adopted for a company if there is a total cost study demonstrating "superior cost performance" for both capital and O&M. DOER Br., at 4; Tr., at 2860, 3983.

This belief is incorrect, as there have been a number of comprehensive PBR plans adopted by the Department without the total cost study or a finding of superior cost performance for both capital and O&M proposed by the DOER:

- A comprehensive PBR was applied to NYNEX in D.P.U. 94-50 and no total cost study was presented in that proceeding,
- A comprehensive PBR was applied to Berkshire Gas Company in D.T.E. 01-56 and no total cost study was presented in that proceeding,
- A comprehensive PBR was applied to Blackstone Gas Company in D.T.E. 01-50 and no total cost study was presented in that proceeding,
- A comprehensive PBR was applied to Boston Gas Company in D.P.U. 96-50 but no total cost study or finding of superior cost performance was used in that proceeding to support any specific value in the approved PBR,
- A comprehensive PBR was applied to Boston Gas Company in D.T.E. 03-40; a total cost study was presented in that proceeding and discussed in the Department's Order, but the Department determined that the study was distorted. Moreover, the Department rejected the claim that Boston Gas was a superior cost performer. D.T.E. 03-40, p. 485. With the exception of the plan term, Bay

> State's PBR proposal is identical to that approved by the Department in D.T.E. 03-40.

The Department does not require a finding of "superior cost performance" for the capital and O&M portion of a company's costs before it approves a comprehensive PBR plan. If such a finding were necessary before a comprehensive PBR could be applied, the Department would not have approved any comprehensive PBR plans in Massachusetts.

This misunderstanding of Department PBR precedent permeates all of the DOER's arguments in its brief and in the testimony of Dr. Pereira. For example, when Dr. Pereira was asked whether he was aware of the Department precedents with regard to the use of capital costs in the model which was developed in D.T.E 03-40, he replied that "I'm a little bit aware." Tr., at 2878-79. When he was asked to demonstrate that the DOER's alternative PBR proposal was consistent with the objectives the Department set forth in its order in D.P.U. 94-158, he indicated that "I don't know what 94-158 is, but I imagine I can look it up." Tr., at 2892.

In addition to misunderstanding Department precedents, the DOER appears confused about its own two X-factor PBR proposal. In his direct testimony, Dr. Pereira states that the Company's proposed PBR plan "represents a step backwards in the evolution of incentive regulation as applied by the Department over the past decade. In particular, the Company is proposing a partial PBR that caps only a portion of their costs." Exh. DOER-1, p. 3. While this is not true, in that same testimony Dr. Pereira, himself, recommends a partial PBR ("I recommend a partial application of the Company's proposal for the PCI to the portion of cast-off rates that relate to O&M costs"). Exh. DOER-1, p. 7. In his oral testimony, Dr. Pereira modified his position to say that he was in fact proposing a comprehensive PBR. Tr., at 2858, 3983-3984.

Yet in its Brief, the DOER is apparently now back to its original position, since it claims that there is insufficient information in the record to develop a comprehensive PBR that applies to both capital and O&M costs, so the Department should simply apply the proposed PBR formula to O&M costs. DOER Br., at 7-8.

The DOER's proposals are not consistent with any PBR plan approved by the Department. Although the Department has approved both rate freezes and index-based PBR plans, the two have never been applied to different sets of costs in the same PBR formula. Dr. Kaufmann has also indicated that a rate freeze now would not likely be appropriate for gas companies in the Northeast. Tr., at 738-39.

4. <u>DOER's Two X-Factor Proposal Is Unfounded, Arbitrary, and Contrary to the Department's Objectives for Incentive Regulation</u>

In addition to being inconsistent with Department precedents, Dr. Pereira's proposal for a PBR plan with two different X factors is arbitrary, not well conceived, and contrary to the Department's objectives for effective incentive regulation. Implementing his proposal would represent a significant step backwards in the evolution of the Department's PBR policy and would have extremely negative effects on the other gas and electric companies in Massachusetts as well as for the customers of those companies.

Dr. Pereira's recommendation for two different X factors, one to be applied to O&M costs and one to be applied to capital costs (which would result in a rate freeze for capital costs), rests on the false premise that Bay State improved its O&M cost performance, but not its capital cost performance, while it was under a rate freeze. Exh. Exh. DOER-1, p. 6; DOER Br., at 5, 7.

To support his claim, Dr. Pereira compared changes in the Company's capital quantity index over the 1993-2000 period to changes in its capital quantity index over the 1998-2000 period. These comparisons are meaningless, since the periods Dr. Pereira uses do not correspond to the years before (i.e. 1993-1998) and during (i.e. 1998-2003) Bay State's rate freeze. Moreover, Dr. Pereira's analysis distorts the efficiency gains that the Company achieved in its use of capital during the rate freeze. Exh. DTE-4-36. The table in Exhibit DTE 4-36 shows that Bay State's capital input quantity index grew by 3.04% per year in the pre-freeze period, compared with 1.21% growth per year in the freeze period. Bay State, therefore, achieved a 60% deceleration in the growth of its capital inputs while under the rate freeze. RR-DTE-162 (Revised), p. 2. This capital cost improvement during its rate freeze is comparable to the O&M cost trend cited favorably by the Department in D.T.E. 03-40 and used by the Department to support a consumer dividend in that case of 0.3%. Dr. Pereira ignores this evidence that directly contradicts his rationale for two X-factors. RR-DTE-162 (revised), pp. 1-2.

The recommendation to restrict the application of the PBR formula to O&M costs is also arbitrary. Dr. Pereira has arbitrarily chosen different X-factor rate adjustment formulas for different cost components of Bay State's operations without providing any theoretical foundation or empirical evidence to support his recommendations. RR-DTE-162 (revised), p. 4. Dr. Kaufmann has pointed out that with different X factors in the same PBR plan, the Company's incentive to pursue cost efficiencies will be distorted. A company under this type of plan would naturally consider how reductions in different sets of costs may impact its respective future X factors. RR-DTE-162 (Revised), p. 4. For example, a company may decide simply to forego cost reductions in an area where costs have already been cut, because doing so makes other areas look inefficient by comparison thereby leading to higher X factors for those cost components in the future. This would be contrary to the Department's objectives to promote allocative efficiency. RR-DTE-162 (Revised), p. 5.

Under Dr. Pereira's proposal, the review of PBR plans would also become much more cumbersome and costly. There would be incentives for parties to a proceeding concerning a PBR plan to identify relatively less efficient cost areas and propose higher X factors for these areas. This would then prompt new areas for time-consuming discovery and disputes in the consideration of PBR plans. Id. This would, in turn, increase regulatory costs, contrary to the Department's objectives for incentive regulation.

Dr. Pereira either misunderstands or misrepresents the regulatory decisions in Canada that he cites in support of his proposal for a partial PBR, or two X-factor plan. Exh. DTE-DOER-1-3. The Ontario plan referred to by Dr. Pereira for electric distribution companies did not apply different indexing formulas to O&M and capital costs, although it did construct an inflation measure which used different input price subindices for capital and O&M inputs. RR-DTE-162 (Revised), p. 2. Dr. Pereira claims that the Enbridge Gas Distribution PBR plan in Ontario is an example of a PBR applied only to a portion of a company's costs due to the "lack of available data". Exh. DOER-1, p. 3. The lack of data had nothing to do with why a targeted PBR plan was applied to Enbridge's O&M costs. In fact, the plan was a trial that was intended to be a transition to a comprehensive PBR, but Enbridge did not renew the plan when it expired. One of the reasons it was not renewed was that it did not have an earnings sharing mechanism, in part, because the PBR plan was partial, or targeted, so it was more difficult to design an earnings sharing mechanism that reflected only the gains associated with the targeted cost components. RR-DTE-162 (Revised), pp. 2-3.

Recently, the Ontario Energy Board has rejected the approaches tried in the Enbridge case cited by Dr. Pereira. Dr. Kaufmann was an advisor to the Ontario Energy Board during the 2004-2005 Natural Gas Forum, and in this proceeding he has provided his report to the Ontario Energy Board prepared in September 2004 as well as the Board's final report filed in March 2005. RR-DTE-26; RR-DTE-162 (Revised), pp. 3-6. The Board specifically rejected the concept that PBRs should be targeted so as to apply to only some costs.

> A related matter is whether the IR (incentive regulation) framework should be comprehensive or targeted – in other words, whether the plan should apply to all costs or only to some costs. The targeted approach was tried with the Enbridge plan. The comprehensive approach was used for Union and for Ontario's local electricity distribution companies, and it is the more common approach in other jurisdictions. The Board's view is that the targeted approach did not work effectively because it diluted and distorted the incentives, and that a comprehensive model is preferable.

RR-DTE-162, p. 3 (Revised), p. 3, citing <u>National Gas Regulation in Ontario: A Renewed Policy Framework</u> (March 2005).

The Enbridge PBR plan is similar to that proposed by Dr. Pereira in this case, as it featured an indexing formula that applied to O&M costs while capital costs were to be frozen during the term of the PBR plan. The Ontario Energy Board explicitly rejected this type of model citing the distorted incentives it created similar to the distortions Dr. Kaufmann has pointed out would result if such a plan was implemented in Massachusetts. RR-DTE-162

(Revised), p. 5. Therefore, the Ontario decisions cited by Dr. Pereira do not support his plan and, in fact, directly contradict it.

The DOER states that Bay State acknowledges that its PBR cannot meet the requirements of the Boston Gas Company PBR precedent. DOER Br., at 6. This is incorrect. The Company has not only proposed the same PBR mechanism (except for the term) and the same price cap formula as was approved in D.T.E. 03-40, but presented the same types of evidence used in D.T.E. 03-40 to determine an appropriate consumer dividend. In addition, Bay State presented evidence that attempted to respond to the concerns the Department expressed with the econometric cost study presented in D.T.E. 03-40. Compare D.T.E. 03-40, at 438-41 to Exh. BSG/LRK-1, p. 14. While the DOER finds fault with the Company's O&M cost study, it is not able to present any alternative methods for remedying the Department's concerns in D.T.E. 03-40. When asked "Do you have any recommendation as regards to a way of overcoming their problem, taking into account capital costs in the cost model?" Dr. Pereira replied, "No, I do not. If Dr. Kaufmann and his firm couldn't do it, then I don't think I could do it, either." Tr., at 2880.

In conclusion, Dr. Pereira's proposals would appear to address a non-existent problem, since Bay State improved both its O&M and capital cost performance during its rate freeze. The evidence in this proceeding clearly supports applying a 0.3% consumer dividend to both O&M and non-O&M (capital) costs. Moreover, the DOER misunderstands the Department's policy on PBR. Nothing in past Department precedents or the current proceeding supports a restricted application of Bay State's PBR to only its O&M costs. Dr. Pereira's proposal is unprecedented with respect to Massachusetts PBR plans, and this form of PBR has been specifically rejected by the Ontario Energy Board. Compared with Bay State's PBR proposal, Dr. Pereira's proposal would unquestionably produce inferior performance incentives for the Company and ultimately fewer benefits for Massachusetts customers. His proposals are therefore also incompatible with the Department's objectives for incentive regulation and should be rejected.

K. The Attorney General's Comments on Bay State's PBR Plan

The Attorney General criticizes Bay State's PBR plan and opposes the exclusion of SIR program costs from the operation of the PBR price index. The Attorney General claims that it is Department policy to allow a utility to use the industry average productivity offset only when it can show that its cost is at or below that of the industry as adjusted for the particular characteristics of the utility. He claims the Company's proposal fails to include all costs of distribution service and therefore fails to meet this purported Department's standard. AG Br., at 32.

As discussed above, this is not Department policy. The Department has approved several comprehensive PBR plans using industry average productivity offsets for utilities that did not present econometric evidence on their cost performance relative to the industry. The reference in the Attorney General's Brief, at 32, does not support his claim, nor do any other findings in D.P.U. 96-50 cited by the Attorney General. Moreover, the Attorney General's statements about total cost econometric analyses presented in this proceeding are irrelevant, since the capital costs used in these studies are characterized by the same capital vintaging concerns which the Department has found leads to "distorted" econometric results. Boston Gas Company, D.T.E.

03-40, p. 485. In addition, Bay State has in fact presented evidence demonstrating that both its capital and O&M cost performance improved during its rate freeze. Exh. DTE-4-36.

The Attorney General claims that "Mr. Kaufmann's productivity analysis fails to recognize that Bay State Gas is part of NiSource." AG Br., at 33. This is incorrect. Rather, Dr. Kaufmann's approach accurately assessed the performance gains that Bay State has achieved since it became part of NiSource. It would have produced a distorted measure of those gains if Dr. Kaufmann's cost model controlled for the fact that Bay State was part of NiSource, as the Attorney General appears to propose. Exh. DTE-4-22.

The objective of Dr. Kaufmann's benchmarking study was to obtain the best possible estimate of how efficient Company management was in controlling costs, given the factors that are beyond its control that cannot be managed. The relationship between Bay State and NiSource is not a condition beyond Company control. In fact, it expressly is within the Company's control as it reflects decisions by the Company. Any efficiencies that derive from such a structure *must* be reflected in an econometric assessment of Bay State's efficiency. If the Company has in fact become more efficient from this structure, then it should be reflected in the econometric benchmarking evaluation, since this reflects changes (including organizational changes) that management has undertaken to become more efficient. Therefore, far from biasing the efficiency calculation as the Attorney General implies, the efficiency calculation would be incorrect if it attempted to control for the affiliation of Bay State and NiSource. Exh. DTE-4-22.

The Attorney General claims the Company should not be allowed to "pick and choose" the parts of the PBR that it prefers. AG. Br, at 34. The Attorney General claims that the

Company's PBR proposal denies customers the benefit of a first generation PBR plan that should have a consumer dividend of between 0.5% and 1.0%, while also denying them the benefit of second generation PBR plan that should have a 10-year plan term. AG Br., at 34-35 and n.18.

These claims are incorrect as a statement of Department policy. The Department has indisputably approved "first generation" PBR plans that contain both a five-year term and a consumer dividend of less than 0.5% to 1.0%. The relevant precedent is the Department's most recently approved PBR plan, for Blackstone Gas, D.T.E. 04-79. This is a "first generation" PBR plan with a term of five years and an overall X factor of 0.5%. Given that the mostly recently approved "net productivity growth and input price growth" factor for Boston Gas was 0.11%, the approved consumer dividend for Blackstone Gas is accordingly 0.39%.

The Attorney General also misrepresents Bay State's proposals on both the consumer dividend and the plan term, both of which are based on Department precedent. Regarding the consumer dividend, the Company's proposal was linked directly to the evidence reviewed by the Department in D.T.E. 03-40 for determining a reasonable consumer dividend. In D.T.E. 03-40, the Department first assessed the company's performance in the expired PBR plan, and then considered the implications of this evidence for the potential to achieve incremental productivity gains. Exh. BSG/LRK-1, p. 11. The Department's findings in D.T.E. 03-40 led to an approved consumer dividend of 0.3%. Similar analyses showed that Bay State has no more, and perhaps fewer, opportunities to achieve additional productivity gains than Boston Gas did at the time D.T.E. 03-40 was approved. The evidence therefore shows that the consumer dividend established in that proceeding should be an upper bound on a reasonable consumer dividend for the Company in this proceeding. Exh. DTE-4-27; see also, Boston Gas Company d/b/a KeySpan Delivery New England, D.T.E. 03-40, at 487 (2003).

The Company selected a plan term of five years because it was most consistent with Department PBR precedents. Tr., at 687-88. The Department has approved four PBR plans for gas utilities. Exh. BSG/LRK-1, p. 7. Of these, two had five-year terms, including the most recently approved plan for Blackstone Gas Company. Exh. BSG/LRK-1, p. 7. Two plans had 10-year terms, but one of these was a plan for Berkshire Gas Company that included both rate freeze and rate indexing terms which together summed to 10 years. Exh. BSG/LRK-1, p. 7. The only plan with 10 years of rate indexing is the updated plan for Boston Gas Company, in D.T.E. 03-40. Exh. BSG/LRK-1, p. 7. The Company believed that this precedent was the least applicable to its situation. Like Blackstone Gas and Boston Gas in D.P.U. 96-50, the Company was proposing rate indexing for the first time, and the precedents set in those plans supported a term of five years. Exh. BSG/LRK-1, p. 7. Bay State was also coming off a five-year rate freeze, and if it proposed an indexing term of five years it would be consistent with the Berkshire Gas precedent, where the rate freeze and indexing terms summed to 10 years.

The Attorney General claims that the SIR proposal "defeats the whole purpose" of the price cap index and the PBR. AG Br., at 35. This is incorrect. As Dr. Kaufmann stated, the SIR is focused on public safety objectives that are complementary to, but distinct from, the efficiency gains that are promoted by PBR. Tr., at 677-78; Exh. DOER-1, p. 6. It is appropriate for PBR plans to contain separate adjustment mechanisms focused on achieving complementary aims that are not likely to be achieved by the main PBR mechanism. Tr., at 679. An example discussed above is the recent PBR plan in Victoria, Australia that includes a special adjustment to recover the costs of replacing all existing meters on the system with interval meters. Tr., at 679-80. The pattern and magnitude of steel replacement expenditures that Bay State will undertake is also unique and will not be reflected in the industry's historical experience used to set the terms of the PBR formula. Tr., at 678-79. In addition, the SIR is likely to promote efficiency and customer benefits compared with the alternative of not having a SIR, since the SIR will lead to savings in procurement and regulatory costs. Exh. BSG/Rebuttal-5, p. 7; Tr., at 756-57. This does not defeat the purpose of PBR, as the Attorney General suggests, but rather will promote the Department's objectives for incentive regulation. The SIR mechanism, therefore, represents an additional adjustment mechanism that allows the Company to undertake steel replacement investments efficiently, for the benefit of customers, while at the same time giving the Company a reasonable opportunity to achieve its allowed rate of return.

The Attorney General is also incorrect in arguing that Bay State's SIR proposal biases the inflation and productivity factors used in the price cap index formula. AG Br., at 37. There is nothing in the record to support the Attorney General's opinion, which is incorrect. Bay State has proposed a comprehensive PBR plan plus a SIR mechanism to recover the costs of steel replacement expenditures needed to achieve public safety objectives but not reflected in the industry's historical experience used to set the terms of the price cap index. The SIR has been carefully designed so that it does not lead to "double dipping" (i.e. double counting) of steel replacement costs. Tr., 684. No double counting of steel replacement costs means that whatever rate adjustments result from the SIR are mathematically equivalent to the rate adjustments that would have occurred if those costs had instead been recovered through the Z factor. The Z factor, like the SIR, is designed to collect company-specific costs that are not otherwise reflected in the price cap index parameters, but Bay State did not propose to use the Z factor to recover steel replacement costs because this element has been defined more narrowly in Massachusetts. Tr., at 751-52. However, Z factors are part of the PBR plan approved in D.T.E. 03-40 as well as other PBR plans approved by the Department, and the presence of Z factors does not bias the other elements of the price cap index. Because the SIR has been designed to be mathematically equivalent to a Z factor, it also does not bias the productivity and inflation elements of the price cap index formula.

XI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

Bay State's capital structure, cost of long-term debt, and recommended return on equity, are presented in the testimony of Paul R. Moul. Mr. Moul is well-known to the Department and is familiar with Department standards with respect to capital structure and rate of return. He has testified on these issues before the Department for many years in over 25 proceedings. Exh. BSG/PRM-1, Appendix A, p. 1; Exh. DTE-13-1.

Mr. Moul's testimony is presented in two exhibits; the first contains his analysis and recommendations on capital structure and the return on equity. It includes Appendices that summarize his experience and qualifications and provides explanations of the various methods he relies on to evaluate the cost of equity for Bay State. Exh. BSG/PRM-1. Mr. Moul's second exhibit contains the schedules supporting his testimony. Exh. BSG/PRM-2.

B. Capital Structure

Bay State's proposed capital structure consists of its actual capital structure as of December 31, 2004, which is proformed for certain known and measurable changes that have occurred through August 1, 2005. According to Department precedent, Mr. Moul removed the investment in associated companies as well as unamortized goodwill from the Company's equity account. Exh. BSG/PRM-1, pp. 20-21; Exh. BSG/PRM-2, Schedule PRM-5, updated in RR-DTE-51, Att. p.2. The pro forma adjustments to long-term debt consist of a refinancing of $10 million of long-term debt which occurred on June 21, 2005 and the issuance of $5 million of long-term debt on August 1, 2005. The Department has routinely accepted such pro forma adjustments to the debt and equity accounts of gas and electric companies. Exh. BSG/PRM-1, p. 21; Tr. 1159-60; RR-DTE-51, Att. p. 3. All of these changes are found in Exhibit RR-DTE-51, which updates Mr. Moul's Schedules PRM-1, PRM-5 and PRM-6. As a result of these adjustments, Bay State's capital structure consists of 46.05% long-term debt and 53.95% common equity.

1. <u>The Attorney General's Capital Structure Arguments</u>

The Attorney General's witness, Timothy Newhard, recommends a capital structure for Bay State that contains a debt ratio of "between 55% and 65%." He also recommends that short-term debt be included in the Company's capital structure. Mr. Newhard contends that the

Company's capital structure is "artificial" since its parent holds "essentially all" of its outstanding debt. Exh. BSG-AG-1-16, p. 1. The Attorney General's brief proposes short-term debt in the Company's capital structure but does not address Mr. Newhard's proposed debt ratio of 55-65%. AG Br., at 95.

As a preliminary matter, $58.5 million of Bay State's long-term debt is held by outside institutional investors, including the First National Bank, State Street Bank, and Boston EquiServe, and is not held by Bay State's parent. Tr., at 3744. Thus, Mr. Newhard is incorrect when he claims that Bay State's parent holds essentially all of its debt.

A long-term debt percentage of 55%-65%, as recommended by Mr. Newhard, contains significantly more debt than is customary for a gas distribution company. Mr. Moul testified that it would be imprudent for Bay State to have as much debt for ratemaking purposes as Mr. Newhard recommends. Tr., at 3744-46. In fact, the trend during the 2000-2004 period has been towards less debt and more equity in the capital structures of natural gas companies. Tr., at 3745. In 2004, Mr. Moul's comparison group of gas distribution companies had an average debt percentage of 45.5%, which was a decline from higher levels held in 2001 and 2002 of 51.5-50.4%. Exh. BSG/Rebuttal-3A.

To support his proposed 55-65% debt ratio, Mr. Newhard contends that some investment analysts will rate companies in the utility industry with a total debt ratio of 55%-65% between BBB and A. The Standard & Poor's document that Mr. Newhard uses to support this statement is over a year old and clearly states that Standard & Poor's uses many other factors besides total debt ratios, or for that matter any financial ratios, in rating utility companies. Exh. BSG-AG-1-

16, Attachment 2, pp. 1-4. This exhibit does not, in fact, support Mr. Newhard's recommendation.

It has been the Department's policy to accept a utility's test year-end capital structure adjusted for known and measurable changes, unless the capital structure deviates substantially from sound utility practice. Boston Gas Company, D.T.E. 03-40, p. 319 (citing, High Wood Water Company, D.P.U. 1360, at 26-27 (1993)). It is readily apparent that Bay State's long-term debt ratio of 46.05% is very close to the industry norm of 45.5% represented by the average long-term debt ratio of the comparison group. Exh. BSG/Rebuttal-3A; RR-DTE-51 (Supplemental), p. 1. It is a reasonable and prudent level of long-term debt, and there is no evidence that it deviates substantially from sound utility practice. Exh. BSG/Rebuttal-3A; RR-DTE-51 (Supplemental), p. 1.

There is no support for Mr. Newhard's proposed long-term debt ratio in the record, and therefore it should be rejected.

The Attorney General also recommends that short-term debt be included in the Company's capital structure. AG Br., at 95. This proposal would reduce Bay State's revenue requirements by $12 million. AG Br., at 97. He proposes a capital structure including short-term debt that totals $579,784,283, which is far larger than Bay State's rate base. Exh. BSG-AG-1-16, Attachment 1, p. 1. It would be totally inappropriate to include short-term debt in the capital structure of Bay State, since short-term debt is not used to finance Bay State's rate base. The Company's proposed total pro forma capitalization, consisting of long-term debt and common equity, is $398,440,703 and matches very closely to the Company's rate base of $397,095,644.

Tr., at 3746-47; Exh. BSG/PRM-2, at Sch. PRM-5; RR-DTE-51, p. 2; Exh. BSG/JES-1, at Sch. JES-1. Mr. Newhard has proposed a capital structure that is larger than the Company's rate base by approximately $182 million, roughly the average monthly amount of short-term debt for Bay State during the test year. Mr. Newhard uses another calculation where his proposed capitalization is $153 million larger than the Company's rate base. RR-DTE-118. If the Department were to accept a rate base for Bay State that matched the total capitalization proposed by Mr. Newhard, the Company's required return on rate base would be significantly larger than what has been proposed by the Company. Furthermore, the majority of the Company's short-term debt is used to finance purchased gas costs, as well as, gas storage costs. Exh. AG-1-2, (Annual Return for 2004). The cost of that short-term debt is already recovered in Bay State's cost of gas adjustment clause. Tr., at 3747-48. If Mr. Newhard's proposal were adopted and short term debt were included in the capital structure for base rates the Company would recover short-term debt costs twice.

The Department regularly excludes short-term debt from a company's capital structure, because short-term debt is generally not used to finance assets in rate base, and short-term interest rates are often too volatile to be representative of long-term capital costs. <u>Fitchburg Gas and Electric Light Company</u>, D.T.E. 02-24/25, at 209 (2002). The Attorney General refers to <u>Blackstone Gas Company</u>, D.T.E. 01-50 (2001) and <u>Wylde Wood Water Works, Inc.</u> D.P.U. 86-93 (1987) in support of the proposition that short-term debt should be included in the capital structure. AG Br., at 95. However, these cases do not support the Attorney General's proposal in this case. They involve small utilities (the requested increase in rates for the <u>Wylde Wood</u>

case was only $28,000) where the Department determined that a hypothetical capital structure was appropriate. In the Wylde Wood case, the Department based the company's cost of debt on two notes with fixed interest rates. D.P.U. 86-93, at 26. This is not comparable to the Attorney General's proposal in this case to include over $150 million in short-term debt in Bay State's capital structure. When the Department applies its net plant test to a utility's proposed new financing, it uses a utility's long-term debt, not short-term debt, when determining total capitalization under the test. Bay State Gas Company, D.T.E. 04-80, at 6 (2004).

Bay State's capital structure of long-term debt and equity almost exactly matches its rate base, and the Attorney General has presented no evidence that short-term debt is being used to finance rate base assets. Although the Attorney General suggests that "short-term debt is a source of low-cost financing," the short-term Federal funds rate has been rising steadily over the past year. AG Br., at 97; Exh. BSG/Rebuttal-3; Tr., at 3977. To use current short-term debt rates to set long-term base rates for the Company that will be subject to a five-year PBR plan, as the Attorney General suggests, would be irresponsible. Furthermore, the Department has indicated that including short-term debt in a company's capital structure may require significant changes in the Department's regulatory policies. Fitchburg Gas and Electric Light Company, D.T.E 02-24/25, at 213, n. 90.

The Attorney General proposes including short-term debt in Bay State's capital structure solely to reduce the Company's revenue requirements, and the proposal should be denied.

C. Cost of Long-term Debt

Bay State's proposed long-term cost of debt is based on the long-term debt issued by the Company as of December 31, 2004 and updated for the issuance of a $10 million long-term note, June 21, 2005 and a $5 million long-term note on August 1, 2005. Exh. BSG/PRM-1, p. 21-22; Exh. BSG/PRM-2, at Sch. PRM-5. The adjustments are shown in the updated Schedule PRM-6 filed as Attachment RR-DTE-51, p. 3. The Company's overall composite cost for long-term debt is 6.12%, shown on Schedule PRM-1 filed as Attachment RR-DTE-51, p. 1.

D. Rate of Return on Equity

1. <u>Introduction</u>

Bay State proposes the cost of common equity of 11.5% recommended by Mr. Moul. This results in a proposed weighted overall cost of capital of 9.02% shown on Exh. BSG/PRM-2, Sch. PRM-1, updated in RR-DTE-51. This overall cost of capital would provide the Company with the ability to attract capital on reasonable terms. Exh. BSG/PRM-1, p. 2.

Mr. Moul's recommended cost of common equity was based on capital market financial data relied on by investors to assess the relative risk and cost of equity. To determine the cost of equity for Bay State, Mr. Moul relied on four well-recognized measures of the cost of equity: the discounted cash flow ("DCF") model, the risk premium ("RP") analysis, the capital asset pricing model ("CAPM"), and the comparable earnings ("CE") approach.

These models were applied with the market and financial data from Mr. Moul's comparison group of five natural gas companies, also referred to by Mr. Moul as the Gas Group.

Since Bay State has no publicly traded stock, Mr. Moul used the Gas Group as a proxy for Bay State's cost of equity. This Gas Group consists of natural gas companies that: (1) are included in the Value Line Investment Survey; (2) have operations in the Northeastern and Southeastern regions of the United States; (3) have publicly traded stock; (4) have not cut or omitted their dividends since 2000; (5) are not currently the target of a merger, acquisition, or self-induced sale; and (6) have at least 80% of their operations represented by gas operations. The five companies are: AGL Resources, Inc., New Jersey Resources Corp., Piedmont Natural Gas Co., South Jersey Industries Inc. and WGL Holdings, Inc. Exh. BSG/PRM-2, at Sch. PRM-3, p. 2; Exh. BSG/PRM-1, pp. 13-14.

Mr. Moul's recommended cost of equity was derived from the results of the various methods on which he relies. In general, the use of several methods rather than a single method provides a superior foundation to arrive at the cost of equity. At any point in time, depending on extraneous factors that may influence the market, reliance on a single method can provide an incomplete measure of the cost of equity. Exh. BSG/PRM-1, p. 4. In addition, no one method can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the company being evaluated. Exh. BSG/PRM-1, p. 22. Each of the methods Mr. Moul uses contains certain incomplete and/or overly restrictive assumptions and constraints, and therefore he has considered the results of a variety of methods. Exh. BSG/PRM-1, p. 22. The following table summarizes the costs of equity produced by each of the approaches Mr. Moul relied on:

Method	Cost of Equity
DCF	10.21%
RP	11.75%
CAPM	12.01%
CE	13.70%

Exh. BSG/PRM-1, p. 5.

At this point in time, the DCF model is producing atypical results because it is the only model that provides a cost of equity less than 11% and barely provides a double digit cost of equity. Exh. BSG/PRM-1, p. 5; Tr., at 1180. This is due to the current unfavorable investor sentiment for gas companies that is indicated by the Value Line Timeliness Rank for the Gas Group of “4”. Exh. BSG/PRM-1, p. 5. This places gas companies in a below average category and indicates that they are relatively unattractive investments. Exh. BSG/PRM-1, p. 5. Natural gas distribution companies are currently ranked 97 out of 98 industries for probable performance over the next twelve months. Exh. BSG/PRM-1, p. 5. As a result, Mr. Moul recommends less reliance on the DCF method in this case. Exh. BSG/PRM-1, p. 5. In addition, Mr. Moul recommends an 11.5% return on equity because the Company’s proposed PBR is designed to be in place for the next five years and the existence of the risk that unforeseen events will occur during the term of the PBR plan. Exh. BSG/PRM-1, p. 6.

In addition to the cost of equity models noted above, Mr. Moul performed a fundamental risk analysis which compared Bay State to the Gas Group and the S&P Public Utilities. Exh. BSG/PRM-1, pp. 13-20. The S&P Public Utilities are identified on Schedule PRM-4 and are a widely recognized index of electric and natural gas companies. Exh. BSG/PRM-1, p. 13; Exh. BSG/PRM-2, Sch. PRM-4, p. 3. In several important aspects, particularly its weaker credit quality rating, its small size, its higher operating ratio and its weaker interest coverage, Bay State is considered riskier than the Gas Group. Exh. BSG/PRM-1, p. 19. As a result, Bay State Gas Company would have a higher cost of equity than that indicated for the Gas Group. Exh. BSG/PRM-1, p. 19. However, Mr. Moul has made no adjustment for this higher risk of Bay State. Therefore, the cost of equity indicated by the Gas Group provides a conservative basis for measuring Bay State's cost of equity. Exh. BSG/PRM-1.

There are also a number of risk factors affecting the natural gas distribution business and Bay State that the Department should take into consideration in determining Bay State's cost of common equity. The recent high gas commodity prices and the volatility of those prices has had a negative impact on gas distribution company customers and has resulted in the decline of average use per customer and the number of new customers selecting natural gas to meet their energy needs. Exh. BSG/PRM-1, pp. 6-7. As the unbundling of rates and the implementation of customer choice has taken place and the industry has become more competitive, its risk has increased. Exh. BSG/PRM-1, p. 6. The risk for gas distribution companies will continue to rise due to the availability of customer-owned transportation gas and the uncertainty of delivery of volumes to dual fuel customers on a company's system. Exh. BSG/PRM-1, p. 7. As large end-users take advantage of competitive service offerings, natural gas companies continue to face significant competition from alternative energy sources, particularly fuel oil. Exh. BSG/PRM-1, p. 7. The threat of bypass is always present with respect to the Company's large users. Exh.

BSG/PRM-1, pp. 7-8; Tr., at 1154. In addition, many of the Company's residential customers use gas for space heating, which means that there is a large proportion of the Company's residential load that has a low load factor and energy usage that is heavily influenced by the weather, which the Company cannot control. Exh. BSG/PRM-1, p. 9.

The Company will also face a significant amount of risk associated with its large construction program. Over the next five years, the Company's total capital expenditures are expected to be approximately $305 million representing an approximate 63% increase in net utility plant for the Company from the level of December 31, 2004. Exh. BSG/PRM-1, p. 9. Much of this capital expenditure will be for the Company's Steel Infrastructure Replacement ("SIR") program, which will replace aging and leaking unprotected steel mains and other eligible facilities, but is a non-revenue-producing use of capital. Exh. BSG/PRM-1, p. 9. As proposed by the Company, the SIR program rate recovery mechanism will:

- Signal regulatory support for improved reliability and safety of gas distribution infrastructure in Massachusetts;
- Help reduce the gap between Bay State's actual and authorized rates of return;
- Permit Bay State to phase in the rate increases necessary for the SIR investments and avoid the rate shock created by the filing of rate cases;
- Enable Bay State to improve the reliability of its infrastructure;
- Promote job growth and economic development in Bay State's service territory; and
- Avoid frequent base rate increases which will lower the overall regulatory and administrative costs of conducting rate proceedings before the Department.

Exh. BSG/PRM-1, p. 10.

However, the SIR program rate proposal would not eliminate a number of risks for the Company. It would not provide a return on eligible investments during construction. Exh. BSG/PRM-1, p. 10. It would not permit the Company to over-earn its cost of capital because the PBR earnings sharing mechanism should limit any over-earnings. Exh. BSG/PRM-1, pp. 10-11. It also would not reduce the regulatory oversight of the Department. Exh. BSG/PRM-1, p. 11. However, it would more closely match the installation of new facilities with the Department's review of those facilities and ultimately, recovery in rates of the cost of those facilities. Exh. BSG/PRM-1, p. 11; Tr., at 1191.

Without the benefit of the SIR Base Rate adjustment, the Company will not have reasonable opportunity to earn a fair return on its investment, particularly in the context of a five-year PBR proposal. Exh. BSG/PRM-1, p. 11; Tr., at 1149, 1215. The SIR investments are non-revenue producing, which is in contrast to the original installation of the Company's steel mains and facilities in the 1950's, which was associated with the rapid expansion of the Company's distribution network and the addition of many new customers. Exh. BSG/PRM-1, p. 11. The Company forecasts that without the SIR adjustment, its return on equity is expected to fall by an average of 2.3% annually from 2005 through 2009. Exh. BSG/PRM-1, p. 11. This shortfall arises even though Bay State has proposed a PBR plan, because there is no provision in the PBR price cap index mechanism to reflect the requirements of the significant new and accelerated capital investment associated with the SIR program that has not been reflected in Bay State's historic investment experience. Tr., at 1149, 1215; Exh. BSG/PRM-1, pp. 11-12. As indicated by Mr. Bryant, without a SIR adjustment the Company will be required to file frequent rate cases with the Department to avoid excessive earnings erosion associated with the SIR Program. Exh. BSG/PRM-1, p. 12.

2. <u>ROE Models Employed</u>

a. Discounted Cash Flow

The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Exh. BSG/PRM-1, p. 23. The DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. Exh. BSG/PRM-1, p. 23. The DCF cost of equity is based on a combination of these two components representing the total return that investors expect on an investment. Exh. BSG/PRM-1, p. 23. There is a thorough explanation of the DCF method in Appendix E of Exhibit BSG/PRM-1.

The DCF method requires employing an expected dividend yield. Exh. BSG/PRM-1, p. 23. Mr. Moul's analysis produced an adjusted dividend yield of 3.82% from the Gas Group based on the six-month average dividend yield of the Group. Exh. BSG/PRM-1, pp. 15-16. Mr. Moul uses projections of earnings per share growth such as those published by IBIS/First Call, Zacks, Reuters/Market Guide and Value Line to determine the DCF growth rate over a 5-year period. Exh. BSG/PRM-1, pp. 31-33. He uses these analyst forecasts of earnings per share growth and also forecasts of growth in overall corporate profits for 5-year and 10-year periods to determine a growth rate of 5.75%. Exh. BSG/PRM-1, p. 34.

Mr. Moul then adds a leverage adjustment to the dividend yield and growth rate figures. Exh. BSG/PRM-1, p. 35. This is to account for the divergence of market capitalization from book capitalization, which is common in the utility industry today and is the case for the companies in the Gas Group. Exh. BSG/PRM-1, Appendix E, p. 13. When the results of a market-derived cost of equity are applied to the common equity ratio measured at book value, which is the measure used by the Department in calculating the weighted average cost of capital, a financial risk difference is created. Exh. BSG/PRM-1, p. 34. The capitalization of a utility measured at its market value contains relatively less debt and more equity than capitalization measured at book value. Exh. BSG/PRM-1, p. 34. The capital structure ratios measured at a utility's book value, therefore, show more financial leverage, and higher risk than the capitalization measured at market values. Exh. BSG/PRM-2, pp. 34-35. It is therefore necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for rate setting purposes. Exh. BSG/PRM-1. Accordingly, Mr. Moul proposes a leverage adjustment of .64%. Exh. BSG/PRM-1, p. 36.

Mr. Moul proposed this adjustment in the Berkshire Gas Company proceeding, D.T.E. 01-56, and the Boston Gas Company proceeding, D.T.E. 03-40. In both cases, the Department declined to adopt the adjustment. Exh. BSG/PRM-1, p. 36. However, his adjustment addresses the issue of financial risk and is not dependent upon a price-to-book analysis as was suggested by the Department in the Boston Gas order. Exh. BSG/PRM-1, p. 36. Mr. Moul's leverage adjustment is not intended to insure a price to book ratio of 1:1, and the adjustment contains no target price-to-book ratio. Exh. BSG/PRM-1, p. 37. Instead, the adjustment simply recognizes the financial risk difference between the market capitalization and book value capitalization of a utility. Exh. BSG/PRM-1, p. 37. Adding, Mr. Moul's dividend yield, plus growth, plus leverage factors, produces a DCF result of 10.21%. Exh. BSG/PRM-1, pp. 37-38.

b. Risk Premium Analysis

The risk premium analysis is based on the prospective cost of long-term debt, i.e., the yield that a utility must offer to raise long-term debt from investors. Exh. BSG/PRM-1, p. 38. To that yield, a risk premium is added in recognition of the greater risk of common equity over debt. Exh. BSG/PRM-1, p. 38. With this method, the cost of equity is determined by corporate bond yields, plus a premium, to account for the fact that common equity has a greater investment risk than debt. Exh. BSG/PRM-1, p. 38. The risk premium approach is fully explained in Appendix G of Exhibit BSG/PRM-1.

Mr. Moul used a 7% yield as a reasonable estimate of the prospective yield on long-term A-rated public utility bonds for the period proposed in the Company's PBR Plan. Exh. BSG/PRM-1, pp. 38-39. This estimate recognizes that the prospect of maintaining the current low long-term interest rates, or even lower long-term interest rates, is outweighed by the prospect of higher future interest rates, particularly as a result of the policy of the Federal Open Market Committee, which is now in transition and is in the process of raising the short-term Federal Funds rate. Exh. BSG/PRM-1, pp. 39-40. To determine the equity risk premium, Mr. Moul analyzed the equity returns for the S&P Public Utilities compared with the returns on utility bonds. Exh. BSG/PRM-1, pp. 41-42. As a result, he determined a reasonable risk premium of

4.95%. Exh. BSG/PRM-1, p. 43. The overall cost of equity based on the risk premium analysis is therefore 7.0% plus 4.75%, or 11.75%. Exh. BSG/PRM-1, p. 44.

c. Capital Asset Pricing Model

The Capital Asset Pricing Model ("CAPM") is a variation of the risk premium analysis. It employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Exh. BSG/PRM-1, p.95. Aside from the reliance on the risk-free rate of return, the CAPM gives a specific quantification to systematic (market) risk as measured by Beta. Exh. BSG/PRM-1, pp. 44-48. The Capital Asset Pricing Model is fully explained in Appendix H of Exh. BSG/PRM-1. Mr. Moul's CAPM analysis produced a risk-free rate of return of 6%, a leverage adjusted Beta of .85, and a 6% market premium, producing an overall cost of equity of 12.01%. Exh. BSG/PRM-1, p. 48.

d. Comparable Earnings Approach

The comparable earnings approach measures returns expected by investors in non-regulated firms, because the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can effectively compete in the capital markets. Exh. BSG/PRM-1, pp. 48-49. With competition being introduced throughout the traditionally regulated utility industry, returns expected to be realized by non-regulated firms become increasingly relevant in the rate setting process. Exh. BSG/PRM-1, p. 49. The firms selected by Mr. Moul for the comparable earnings approach consisted of non-regulated firms in the Value Line Investment Survey for Windows screened for 6 specific items: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas and Technical Rank. Exh. BSG/PRM-1, pp. 50-51. In his analysis, Mr. Moul used both historical returns and forecasted returns for the non-utility companies. Exh. BSG/PRM-1, p. 51; Exh. BSG/PRM-2, at Sch. PRM-13, (list of non-utility companies and their rating by the six screening factors). The average of the historical and forecasted median rates of return for the comparable earnings analysis was 13.70%. Exh. BSG/PRM-1, p. 52.

3. <u>Position of the Parties</u>

a. Attorney General

The Attorney General's witness, Timothy Newhard, recommends a cost of equity for Bay State of 8.66%, based on two forms of a DCF analysis. AG Br., at 114. The first form used by Mr. Newhard is a constant growth rate DCF, and the second is a two-step DCF that allows for two periods of growth, one short-term and the other long-term. To perform his DCF analysis, Mr. Newhard used Mr. Moul's comparison group. Exh. AG-8, p. 6. Although the Attorney General asserts that he provided "two market based cost of equity analyses," he actually used only one model, the DCF, expressed in alternate forms. AG Br., at 98.

Because Bay State does not have publicly issued common stock and all of its common stock is held by its parent, NiSource, Mr. Newhard began his cost of equity analysis with NiSource's common stock. Exh. AG-8, p. 4. Mr. Newhard undertakes this analysis even though he acknowledges that NiSource's combination of regulated businesses makes a direct comparison to Bay State problematic. Exh. AG-8, p. 5. For example, in addition to gas distribution businesses, NiSource includes the fifth largest gas transmission company in the country as well as electric power operations. Exh. BSG/Rebuttal-3, p. 20. Moreover, Mr. Newhard's analysis of NiSource cannot be relied on because the Department has consistently rejected the use of a parent company in a DCF analysis as a proxy to develop the cost of equity for a subsidiary that has no publicly traded stock. Massachusetts Electric Company, D.P.U. 95-40, at 96 (1995).

In his rebuttal testimony, Mr. Moul identified a number of flaws in Mr. Newhard's analysis and the reasons why the Department should reject Mr. Newhard's recommended cost of equity. Exh. BSG/Rebuttal-3. Most importantly, the rate of return proposed by Mr. Newhard is inadequate to provide the Company with its cost of capital for the five-year period of the Company's proposed PBR. Exh. BSG/Rebuttal-3, p. 2. This is because the 8.66% return recommended by Mr. Newhard will not accommodate any upward movement in capital costs, such as, the upward trend that has recently begun with the progression toward higher interest rates as a result of current Federal monetary policy and other economic factors. Exh. BSG/Rebuttal-3, p. 2. In addition, the 8.66% rate does not come close to the returns actually expected by investors in energy utilities. Exh. BSG/Rebuttal-3, p. 2. For example, the forecasted return on equity expected by investors for Mr. Newhard's (and Mr. Moul's) comparison group is 11.9%, which is far above the 8.66% return recommended by Mr. Newhard. Exh. BSG/Rebuttal-3, p. 2. The rates of return established recently by other state commissions in the United States show that the return proposed by Mr. Newhard is substantially too low. Exh. BSG/Rebuttal-3, p. 2. Single digit returns on equity allowed by state commissions are unusual.

For the period October 1, 2003 to September 30, 2004, the allowed returns on equity by state utility commissions were in the following ranges:

Return on Equity	Number of Decisions	Percent
Less than 10%	3	6%
10% to 10.9%	36	69%
11% to 11.9%	8	15%
Higher than 12%	5	10%

Exh. BSG/Rebuttal-3, p. 6. The average authorized rate of return on common equity for this sample was 10.67%, the median return was 10.50%, and the midpoint return was 11.15%, taken from the overall range of 9.60% to 12.70%. Exh. BSG/Rebuttal-3, p. 6. This data demonstrates that returns below 10% are unusual in rate case decisions. Exh. BSG/Rebuttal-3, p. 6.

The return on equity determined to be appropriate by the Department constitutes a single numerical value that sends a clear signal of the Department's level of support for the utilities regulated in Massachusetts. Exh. BSG/Rebuttal-3, p. 3. The allowed return on equity figure is universally understood and communicates to investors the types of returns they can expect from an investment in a utility operating in the Commonwealth. Exh. BSG/Rebuttal-3, p. 3. The Department cannot ignore those expectations, even in the presence of proposed adjustments to the rate of return on common equity that may be based on reconciling cost recovery mechanisms or other adjustments found in any particular rate case proceeding. Exh. BSG/Rebuttal-3, p. 3. Thus, while the Department clearly has discretion in setting a company's return on equity that may include non-market factors, the final return allowed should not be so low as to send a negative signal to investors about the climate for utilities in Massachusetts. Exh. BSG/Rebuttal-

3, pp. 3-4. The 8.66% return on equity recommended by the Attorney General would send such a negative signal. Exh. BSG/Rebuttal-3, pp. 3-4.

Furthermore, the 8.66% rate of return recommended by Mr. Newhard is occurring during a transition in monetary policy and does not take into account the prospects of higher capital cost rates during the 5-year term of the PPR proposed by Bay State. Exh. BSG/Rebuttal-3, p. 4. If interest rates continue to rise from their recent low levels, the cost of equity determined from recent data will understate future costs of equity. Exh. BSG/Rebuttal-3, p. 4. Although it is possible interest rates could move lower, the recent extremely low rates would indicate that there is more potential for higher rather than lower interest rates in the future. Exh. BSG/Rebuttal-3, pp. 4-5. Over the past year, the Federal funds rate has been increased ten times in 25 basis point increments. Exh. BSG/Rebuttal-3, pp. 4-5; Tr., at 3977.

Mr. Moul identified a number of misspecifications and downward biases in Mr. Newhard's analysis which contributed to the unreasonably low return on equity he recommends. Exh. BSG/Rebuttal-3, pp. 6-7. As a preliminary matter, no single method is sufficiently reliable to establish the cost of equity without further verification. Id. This is particularly true today, given the wide swings in share values and overall general financial market uncertainty. Id. Although Mr. Moul considered four methods in his analysis: the DCF, comparable earnings, capital asset pricing model and risk premium methods. Mr. Newhard did not use any other methods aside from the DCF, which produces the lowest return of all four methods. Id. at p. 8. In addition, Mr. Newhard's approach in this case represents a marked departure from testimony that he submitted in Boston Edison Company, D.P.U. 1350, AT & T

Communications of New England, Inc., D.P.U. 85-136/85-137, and New England Telephone Company, D.P.U. 86-33, where he also used the risk premium approach. Exh. BSG-AG-1-18. Although he provides two forms of DCF, checking one DCF result with another DCF analysis provides no confirmation to verify the reasonableness of the returns produced, since all cost of equity methods contain certain unrealistic or overly restrictive assumptions. The use of more than one method is a far better approach. Exh. BSG/Rebuttal-3, pp. 7-8.

The two-step DCF model used by Mr. Newhard has not found wide acceptance in public utility ratesetting. Exh. BSG/Rebuttal-3. When it has been used by the Federal Energy Regulatory Commission in natural gas pipeline cases, the short-term (5-year) growth rate has been assigned a two-thirds weight and the long-term growth is assigned a one-third weight in order to derive a single growth rate. Exh. BSG/Rebuttal-3, p. 9. This was not the procedure followed by Mr. Newhard. Exh. BSG/Rebuttal-3, p. 9.

One problem of the constant growth DCF used by Mr. Newhard is that it assumes a constant dividend payout ratio. This is not a reasonable assumption when forecasts show higher earnings growth rates than dividend growth rates, and, as a result, the expectation is that dividend payout rates will decline in the future. Exh. BSG/PRM-1, at Appendix E, p. 9. Thus, investors will expect higher earnings growth rates, because with the constant P-E multiple assumption of the DCF, the stock price will appreciate at the earnings growth rate. The Value Line data utilized by Mr. Newhard shows this decline in dividend payout ratios, and therefore the sustainable growth rate formulation of the DCF is a poor choice for measuring return on equity. Exh. BSG/Rebuttal-3, p. 10.

A key component of the constant growth DCF is the assumed return on book common equity. Exh. BSG/Rebuttal-3, p. 11. As mentioned above, Value Line forecasts that the comparison group will earn 11.9% on book common equity during the period 2008 through 2010, a period considered by Mr. Newhard in his analysis. Exh. BSG/Rebuttal-3, p. 11. However, Mr. Newhard's 8.66% recommendation is far below this figure. Exh. BSG/Rebuttal-3, pp. 11-13.

In applying his sustainable growth form of the DCF, Mr. Newhard employed forecasts of future growth from retained earnings published by Value Line. AG Br., at 102. However, Mr. Moul pointed out that growth from retained earnings is a poor choice, and the Attorney General acknowledges certain problems in the assumptions that underline the DCF method. AG Br., at 102, n. 54. When using the Value Line forecasts, it is necessary to adjust those returns from year end to average book common equity, which Mr. Newhard fails to do. Exh. BSG/Rebuttal-3, p. 14. Without this adjustment there is a downward bias in the results because with an increasing book value caused by retention growth, the average book value will be less than year end book value. Exh. BSG/Rebuttal-3, p. 13. Removing this downward bias increases growth from retained earnings by .12%. Id. at 15. Even with this correction, the constant growth rate determined by Mr. Newhard misspecifies the growth in book value forecasted by Value Line. Id. Value Line forecasts book value per share will grow on average by 7.3% for the comparison group, which is far above Mr. Newhard's 5.38% corrected constant growth rate. Id. Making these changes, Mr. Newhard's form of DCF produces an 11.05% return on equity. Exh. BSG/Rebuttal-3, pp. 15-16.

There are other flaws in Mr. Newhard's two-step DCF model. AG Br., at 104. For example, he relies on Thompson Financial (i.e., First Call and Zack's) forecast earnings growth rates for this first step growth rates. Exh. BSG/Rebuttal-3, pp. 15-16. Without any justification, he ignores the forecast earnings growth from Value Line, although he uses the Value Line forecasts for his sustainable growth rate calculations. Exh. BSG/Rebuttal-3, p. 17. If the Value Line forecasts are included in the first step growth rate, the average growth rate increases substantially. Exh. BSG/Rebuttal-3, p. 17.

In addition, Mr. Newhard incorrectly chooses the forecasted growth in GDP as his second step growth rate. Exh. BSG/Rebuttal-3, p. 18; AG Br., at 105. Although forecasts of GDP growth can be used as a proxy for revenue growth, GDP growth cannot be used as a measure of earnings growth. Exh. BSG/Rebuttal-3, p. 18. Forecasted growth of corporate profits provides the correct measure for the second step growth in Mr. Newhard's DCF. Exh. BSG/Rebuttal-3, p. 18; Exh. BSG/PRM-1, pp. 28-29. Using forecasts of corporate profit growth rather than GDP, and adding the Value Line forecasts of earnings growth, increases Mr. Newhard's two step DCF cost of equity from 9.21% (Exh. AG-8, p. 16) to 9.92%. Exh. BSG/Rebuttal-3, pp. 18-19; Tr., at 3748.

Mr. Moul identified another significant downward bias in Mr. Newhard's two-step DCF analysis. He determined, in reviewing Mr. Newhard's spreadsheet models, that for the first step growth, which is based on analysts forecasts of 5-year growth, Mr. Newhard only recognized 4 ½ years of that growth rate. Tr., at 3748-49. When correcting for that downward bias, Mr. Newhard's DCF result increases to 10.12% for the Gas Group. Tr., at 3748-49. When correcting the downward bias in Mr. Newhard's DCF results for NiSource the return increases to 10.18%. Tr., at 3749-50; RR-AG-97.

Mr. Newhard asserts that the business activities of the comparison group include non-regulated businesses, and, therefore, the cost of equity derived from the comparison group overstates the cost of equity for Bay State. Exh. BSG/Rebuttal-3, p. 21; AG Br., at 105. This conclusion is without support in the record, since the vast majority of the operations of the comparison group companies are regulated, and the regulated assets represent 88% of the business segments of the comparison group. Exh. BSG/Rebuttal-3, pp. 21-22. Furthermore, Piedmont Natural Gas Company in the comparison group has almost all of its operations devoted to regulated businesses and yet its technical rank is the lowest of the comparison group. Exh. BSG/Rebuttal-3, p. 22. This indicates that it has a higher risk and higher cost of equity than the other comparison group companies. Piedmont is similar to Bay State in that almost all of Bay State's operations are regulated. Exh. BSG/Rebuttal-3, p. 22.

Mr. Newhard's claim is not correct that 85% of Bay State's costs will be collected "dollar for dollar" if all of its rate request is approved in this proceeding is incorrect. AG Br., at 106. Mr. Skirtich demonstrated that 64-65% of the Company's costs would be subject to a reconciling mechanism if all of the Company's requests were approved in this proceeding, with gas costs being the largest of those costs. Tr., at 3845; Exh. BSG/Rebuttal-3, pp. 21-22.

Mr. Newhard claims that Bay State's proposed pension and PBOP reconciling mechanism, as well as other adjustment mechanisms proposed by Bay State, warrant a reduction in the Company's return on equity. However, Bay State's proposals are not unique in the industry and do not warrant a reduction in its equity return. Many other gas distribution companies have commodity cost of gas recovery mechanisms, as well as mechanisms to recover environmental remediation costs. Exh. AG-20-2; Exh. AG-20-7. Other gas utilities have alternate methods of dealing with issues such pension costs and post-retirement benefits. Exh. AG-20-3. Bay State lacks a weather stabilization clause that is common for most companies in the comparison group. Exh. BSG/Rebuttal-3, p. 23. Atlanta Gas Light, a subsidiary of AGL Resources, which is a member of the comparison group, collects its revenues through a demand charge that is not volumetrically determined, and it does not provide end-users with any commodity. Exh. BSG/Rebuttal-3, p. 23. Consequently, Atlanta Gas Light's revenues are not subject to variations due to uncollectibles, the cost of the gas commodity, conservation measures and weather. Exh. BSG/Rebuttal-3, p. 23. In addition, it has had a pipeline replacement program in effect since 1998 that provides the recovery of capital costs for the replacement of cast iron and unprotected steel mains on a per customer basis. Exh. BSG/Rebuttal-3, pp. 22-23.

In criticizing Mr. Moul's DCF, the Attorney General claims Mr. Moul chose the "highest available" DCF growth rate. AG Br., at 108. This is not the case, as Mr. Moul's choice was made in the context of long-term growth in corporate profits. Exh. BSG/PRM-1, p. 33. The Attorney General also presents a biased representation of the growth rates that Mr. Moul relied on. AG Br., at 108. For example, as shown on Exhibit BSG/PRM-2, at Sch. 9, the Value Line earnings growth rate is 6.40% which is not found in the Attorney General's table on page 108 of his brief or in footnote 55 on that page.

Based on the flaws and biases present in Mr. Newhard's analyses, the Attorney General's recommended return on equity should be rejected.

b. UWUA

The UWUA recommends that the Department set Bay State's return on equity at 8.16%, which represents a 50 basis point penalty below the return recommended by Mr. Newhard to "send the strongest possible signal" to Bay State about the importance of customer service. UWUA Br., at 16-18, 42. UWUA supports this recommendation with references to Bay State call center performance in the 2000-2003 period, and as long ago as 1999, mergers that occurred in 1998 and 2000 and a tragic gas explosion that occurred in 1998. UWUA Br., at 20, 33, 35.

The return on equity penalty proposed by UWUA is inappropriate and unwarranted for a number of reasons. The events cited by UWUA supporting a penalty occurred several years ago, and in one instance in 1998, eight years ago. There is no basis to penalize current management for events occurring that long ago. Furthermore, as UWUA is well aware, Bay State now meets all of its service quality standards in Massachusetts, and has done so since 2002. Therefore, a return penalty attributed to events before 2002 would serve no purpose. Bay State was subject to a substantial service quality penalty in 2000, and its performance improved. Exh. BSG/SAB-1, p. 30. In addition, since the Department's service quality standards already include a penalty mechanism for poor performance, a return penalty, as suggested by UWUA, would amount to a duplication and double-counting of the Department's service quality penalties. Finally, given that, if adopted, a return penalty would stay in effect for the 5 years of Bay State's proposed PBR plan, there would be no opportunity or motivation for the Company to improve performance and eliminate the penalty during the term of the PBR.

For all of these reasons, the UWUA's proposed penalty return should be rejected.

XII. PROPOSED CHANGES TO THE BAY STATE GAS COMPANY TARIFF

The Company's tariff governs its relationship with customers and third-party suppliers establishing the rights and responsibilities of each party. Changes proposed to Bay State's tariff reflect the revised rates and charges, new cost recovery mechanisms and general updates to the tariff to streamline and conform the tariff to existing operations. Exh. BSG/JAF-3, pp. 2-3. The proposed tariff in its entirety, represented as M.D.T.E. Nos. 34 through 68, accompany the Company's petition in this proceeding. In addition, a red-lined version of the tariff showing all changes to the currently effective tariff is provided as Exhibit BSG/JAF-3, at Sch. JAF 3-1.

A. Changes to Service Structure

The Company's overall service structure is largely unchanged under the Company's proposal. Rate Schedules are segregated between firm and interruptible service offerings and between sales and transportation services. In addition, the existing classification of C&I customers on the basis of size and load factor remains intact. More limited changes to the structure of certain rate schedules are proposed. Exh. BSG/JAF-3, p. 3.

1. <u>Dual-Fuel Tariff (proposed M.D.T.E. No. 67) (As modified)</u>

The Company proposes to institute a special provision applicable to firm gas customers with dual fuel capability. The Company constructs facilities and incurs substantial fixed costs in order to provide safe and reliable service to its firm customers under all conditions. The majority of the fixed costs incurred by the Company are recovered through volumetric rates that are specifically designed on the premise that firm customers are full requirements customers of the Company. Exh BSG/JAF-3, p. 4. Customers with dual fuel capability have the option to use an alternate fuel when economic savings can be realized as a result of the differences in commodity fuel costs. As these customers utilize an alternate fuel, they provide no contribution toward the fixed costs incurred by Bay State to provide reliable firm service and, as a result, costs are unfairly shifted to the remaining firm customers. The fixed costs associated with providing firm service to these customers, but are oftentimes not recovered from them, relate to ensuring sufficient distribution capacity to meet their full natural gas needs at any time of the year, including on a design or peak day. Id.

The Company's proposed Dual Fuel Special Provision is a reasoned approach to achieving fairness between firm customers that have dual fuel capability and those that do not. Moreover, the Department approved essentially the same approach for NSTAR Gas Company.

The Duel Fuel Special Provision will be applicable to customers whose annual usage is in excess of 5,000 therms, specifically, customers taking service under Bay State's C&I rate schedules G/T-41, G/T-51, G/T-42, G/T-52, G/T-43 and G/T-53. These C&I customers will be responsible to notify the Company of any duel fuel equipment installed at their facilities. Exh. BSG/JAF-3, p. 5. The Company's initial proposal set out that, in such instances where a customer has dual fuel capabilities, a benchmark usage is established based on the natural gas input ratings of the Customer's dual fuel equipment. Only if the Customer's usage falls below the benchmark does the Special Provision require the customer to pay an additional charge to compensate the Company for the fixed costs of standing ready to serve the customer throughout the year. Exh. BSG/JAF-3, pp. 5-6. During the proceeding the Company modified its proposal by replacing the benchmark usage and associated distribution revenue requirement with a minimum distribution revenue requirement based on each customer's long-run marginal cost revenue requirement. Each customer's long-run marginal costs coming out of this instant case, and each year would be adjusted for inflation at the GDP-PI. See response to DTE-7-19.

The Special Provision applicable to Dual Fuel use ensures that firm customers that desire to benefit from economic fuel switching may do so without shifting costs to other firm customers. Exh. BSG/JAF-3, pp. 6. In addition, the proposal as modified is consistent with Department policy of establishing a minimum distribution revenue requirement, or floor price, for special contract customers at the long-run marginal costs of providing service. These firm dual customers take service under different or unique conditions as compared to the majority of the Company's customers, firm tariff straight gas customers. In that regard they are similar to special contract customers. Thus, being responsible for at least the annual long-run marginal cost revenue requirement, which would still be less than the revenue received from firm tariff straight gas customers, is fair and consistent with Department policy on cost responsibility.

2. Interruptible Transportation Agreement (proposed M.D.T.E. No. 65 and Interruptible Gas Supply Service Agreement (proposed M.D.T.E. No. 66)

The proposed non-price revisions to the current Interruptible Transportation Agreement are two-fold. First, the Company proposes to fully unbundle its interruptible sales and interruptible transportation services by separating the supply service from the local transportation. Exh. BSG/JAF-3, p. 7. The existing service agreement would be replaced with a single unbundled transportation service agreement, which is required for all interruptible customers, and an optional interruptible gas supply service agreement. Exh. BSG/JAF-3, p. 9. These agreements were submitted as Exh. BSG/JAF-4. The proposed changes to the standard interruptible transportation agreement implement the Department's directive that all natural gas LDCs unbundle their burner-tip IS service into city-gate IS service and IT service from the city-gate to the burner-tip and develop terms and conditions for service to all IT customers, regardless of a customer's contractual source of gas. D.P.U. 93-141-A (1996), at 23.

Secondly, the proposed Interruptible Transportation Service Agreement formalizes the winter curtailment period, designated as December 1st through March 31st, when interruptible service will be unavailable. Exh. BSG/JAF-3, p. 6. The winter curtailment provision ensures that non-firm customers make appropriate arrangements to secure alternate fuels and eliminates the potential that such customers could avoid adequate preparations for periodic curtailments jeopardizing service to firm customers. Exh. BSG/JAF-3, p. 7. The winter curtailment provision is an important tool that allows the Company to continue to provide safe and reliable service to its firm customers during critical times during the winter. Bay State provided notice to the Department when it initially implemented the winter curtailment prior to the 2004-05 heating season. Id.

3. Interruptible Standby Gas Supply Service and Service Agreement (proposed canceled M.D.T.E. No. 19 and M.D.T.E. No. 20)

Bay State proposes to eliminate the interruptible gas supply service rate schedules (M.D.T.E. No. 19 and M.D.T.E. No. 20) as there are no customers taking the service and the Company does not anticipate that the service will meet a market need in the future. Exh. BSG/JAF-3 at 9. Elimination of the unneeded service simplifies Bay State's tariff and the necessary administration thereof. Additionally, customers who execute the proposed Interruptible Gas Supply Service Agreement (M.D.T.E. No. 66) will be required to also execute the Interruptible Transportation Agreement (M.D.T.E. No. 65) which includes the various terms that were previously included in the Interruptible Standby Gas Supply Service Agreement. Exh. BSG/JAF-3, p. 10; Exh. BSG/JAF-4.

B. Changes to Distribution and Default Service Terms and Conditions (proposed M.D.T.E. No. 35)

The Company proposes a limited number of changes to the Company's Distribution and Default Service Terms and Conditions (proposed M.D.T.E. No. 35). The first modification clarifies a customer's right to obtain service at a new location even if the customer has a preexisting balance at a previous service location. In order to obtain service at the new location, a waiver is granted allowing the customer to simply transfer any arrearage to the service at the new address if a payment plan is entered into. Exh. BSG/JAF-3, p. 11.

Second, the Company proposes to increase the frequency with which it cashes out non-daily metered transportation service from semi-annually to monthly. More frequent true-ups are beneficial to both the Company and suppliers as imbalances are carried for shorter periods and the cashout price is more likely to be representative of market conditions at the time that variances occur. Exh. BSG/JAF-3, pp. 11-12.

Third, the Company proposes to update its fee schedule for service reactivation, meter tests, customer warrants and locksmith charges. The proposed fees are reflected in Appendix B to the Company's Distribution and Default Terms and Conditions. Exh. BSG/JAF-3, p. 12.

C. Changes to Cost of Gas Adjustment Clause (proposed M.D.T.E. No. 36)

The primary change to Bay State's Cost of Gas Adjustment Clause ("CGAC") is the Company's proposal to implement the Simplified Market-Based Allocation ("SMBA") methodology that is supported by Mr. James L. Harrison in his testimony included as Exhibit BSG/JLH-1. Exh. BSG/JAF-3, p. 12. The first modification to the CGAC necessary to implement the proposed SMBA is to group the current thirteen CGAC customer classes by similar load characteristics, which result in two new CGAC factors; the first is the high load factor customer class and the second is the low load factor customer class. Exh. BSG/JAF-3, p. 13. This revision to the CGAC to reflect a single rate for all high load factor customers and a second rate for all low load factor customers is consistent with the methodologies approved by the Department for Berkshire Gas Company and Fitchburg Gas and Electric Company. Exh. BSG/JLH-1, p. 20. In fact, in its Order to Berkshire Gas, the Department noted that such load factor based GAF is likely to lead to more effective competition by reducing "cherry picking" and "may encourage customers to improve their load factors through improvements in efficiency or through load shifting." Berkshire Gas Company, D.T.E. 01-56 (2002), at 129. Further, the allocation of fixed costs follows a two-step process that first assigns the lowest cost pipeline resources to meet the average summer usage of each load factor customer class. The remaining fixed costs are allocated on the basis of contribution to design day less the initial allocation of pipeline resources. Id.

A second change to Bay State's CGAC is the proposal to revise the CGAC language to more accurately reflect a calculation process which utilizes the Sendout dispatch model output – costs as they are dispatched to serve customer load. This modification will make Bay State's CGAC tariff consistent with Fitchburg Gas and Electric Light Company. Exh. BSG/JLH-1, pp. 22-23.

Finally, the Company has included as Section 15.0 "Bad Debt Expense, creating a separate section for Bad Debt Expense, rather than including and referring to bad debt expense in other sections of the tariff. This section also more clearly describes how the Company has been forecasting and will continue to forecast bad debt expense in its GAF filings, and has been determining, and will continue to determine, actual bad debt expense to which the Company reconciles.

The Department requested modifications to the proposed CGAC during the hearings. RR-DTE-103; RR-DTE-172. Bay State accepts these modifications as requested, as the Company agrees with the Department that these modifications serve to better clarify various provisions, including the removal of certain formula variables and/or terms.

D. Changes to Local Distribution Adjustment Clause (proposed M.D.T.E. No. 37)

Currently, Bay State recovers its Pension and PBOP obligations through base rates approved in D.P.U. 92-111. Exh. BSG/SAB-1, p. 46. The Company is proposing to modify the Local Distribution Adjustment Clause ("LDAC") to include a reconciling mechanism, called the Pension/PBOP Expense Factor ("PEF"), which would allow the Company to recover changes in the Pension/PBOP expense. This ratemaking approach is appropriate given the large financial impact of this element of the Company's cost structure that the Company has little or no control over. Exh. BSG/JAF-3 at 14. The Department approved a similar reconciling pension cost tracking mechanism for Boston Gas Company. D.T.E. 03-40 (2003), at 313-314.

The pension and PBOP reconciling mechanism would recover pension and PBOP expense through a separate factor in the LDAC, the pension and PBOP expense factor ("PEF"). The PEF would include this instant case's test year level of pension and PBOP expense transferred from the Company's base rates to the PEF plus the pension deferral, equal to the difference between the current level of pension and PBOP expense and the transferred amount amortized over a three-year period with appropriate carrying costs. The recovery of pension and PBOP expense through the PEF component of the LDAC would be reconciled with actual expense and any over or under-recoveries reflected as a credit or debit in subsequent periods. Exh. BSG/JAF-3 at 14-15.

Bay State also proposes to modify the tariff to delete references to the prior SQI provision initiated in D.T.E. 97-97 and to replace it with information regarding the Company's current SQI program, as established in D.T.E. 99-84.

Finally, the Company proposes to remove the provision that provides for recovery of Lost Base Revenues through the DSM component of the LDAC, since the Company proposes to reflect therm savings attributable to the delivery of energy efficiency programs in the annual base rate adjustment mechanism ("ABRAM") which is further discussed in the testimony of Mr. Joseph A. Ferro, Exhibit BSG/JAF-2. Exh. BSG/JAF-3, p. 15.

E. Addition of the Annual Base Rate Adjustment Mechanism Tariff (proposed M.D.T.E. No. 63)

Bay State proposes to include in its Tariff as M.D.T.E. No. 63, a new provision - the Annual Base Rate Adjustment Mechanism ("ABRAM"). This new tariff provision sets forth the terms and conditions for making the annual adjustments necessary to implement the Performance-Based Rate ("PBR") program and the Steel Infrastructure Replacement ("SIR") program proposed by the Company, as well as the adjustment to base rates to reflect the reduction in the prior year's annual therm sales due to the delivery of the Energy Efficiency measures. Incorporating the details of the adjustment mechanisms into the tariff clarifies the operation of the programs so the Department and customers understand the basis for the annual changes. Exh. BSG/JAF-2, p. 25.

The Department requested modifications to the proposed ABRAM tariff language. RR-DTE-101; RR-DTE-126. Bay State accepts these modifications as requested, as the Company agrees with the Department that these modifications serve to better clarify various provisions, including definitions of cost items and terms.

F. Reinstatement of the Residential and Commercial Energy Conservation Service ("RCS") Charge (proposed M.D.T.E. No. 68)

The Company discovered, during its review that the tariff sheet that sets out the RCS Charge had been inadvertently omitted from the Company's tariff. The Company, therefore, has proposed to reinstate the tariff. In addition, the Company has added to each rate schedule, information that specifies that the minimum monthly charge would be the sum of the customer charge for that rate schedule and the RCS charge. The addition of this information provides a more accurate explanation of what is actually billed to the customer.

XIII. RATE DESIGN

A. Standard of Review

The Department requires that utility rate structures be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. Berkshire Gas Company, D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; Boston Gas Company, D.P.U. 96-50 (Phase I), at 133. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the consumption of resources used to produce the utility service. Berkshire Gas Company, D.T.E. 01-56, at 135; Fitchburg Gas and Elec. Light Company, D.T.E. 02-24/25, at 252-53. A rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. Berkshire Gas Company, D.T.E. 01-56, at 135; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 252-53.

B. Rate Design Elements, Base Rates and Bill Impacts

Bay State's proposal to update and add certain new rates, services and adjustment mechanisms is consistent with Department precedent and rate design goals of efficiency, simplicity, continuity, fairness, and earnings stability. See Boston Gas Company, D.P.U. 96-50 (Phase I), at 133-36; Boston Gas Company, D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116; See Exh. BSG/JAF-2, p. 2 (summary of schedules).

As noted above, the Company proposes to collect an additional $22,238,326 through its proposed rates, including $17,580,855 through its tariffed base rates. To be consistent with both the Department's rate design goals and the Company's various proposed rate design changes, Bay State needed to shift portions of its proposed revenue increase between its base rates and other cost recovery mechanisms, such as the Local Distribution Adjustment Clause ("LDAC") and the Cost of Gas Adjustment Clause ("CGAC"). See, Exh. BSG/JAF-2, pp. 3-4 (table summarizing difference between Company's proposed revenue and base rate increase) The causes of the difference include (1) the shifting of cost recovery from base rates to the LDAC (pension/PBOP) and CGAC (indirect gas costs), and (2) a portion of the proposed increase being allocated to special contract service. See Exh. BSG/JES-1 (pension/PBOP-related costs); Exh. BSG/JLH-1, pp. 21-24 (new indirect gas costs); Exh. BSG/JLH-1, at Sch. JLH-3-14 (summary).

Consistent with Department precedent and as explained above, the Company allocated revenues to each respective customer class based on the results of Mr. Harrison's Accounting Cost of Service study ("ACOS"). See, Exh. BSG/JLH-1 at Sch. JAF-2-1. Bay State took the following steps to allocate revenue:

1. revenue requirements resulting from the ACOS were set as initial targets to allocate test year base revenue among customer classes;

2. initial revenue targets were evaluated to cap the impact on each customer class at 6% of its total test year revenue, excluding the shortfall due to the residential low-income discount, and the remaining revenue increase was reallocated to other customer classes;[51]

3. each class's total test year revenues were capped at 6% to ensure rate continuity and to limit bill impacts;

4. where customer classes exceeded the 6% cap, the Company reassigned to all other customer classes the remaining revenue shortfall using the total test year revenue allocation method (the ratio of each class' test year revenues to the group's total test year revenues);[52] and finally,

[51] A cap of 6% is consistent with the Company's past practices and the Department's decisions regarding those practices (See Bay State Gas Company, D.P.U. 92-111 and Bay State Gas Company, D.P.U. 95-104).

[52] This allocation of the revenue increase is consistent with Department policy and the Company's practice in its previous rate proceedings. In some classes the allocation of the low income discount has pushed bill impacts above the 6 percent cap increase to each classes total revenues. Id.; Exh. BSG/JAF-2, p. 12., Exh. BSG/JAF-2, Sch. JAF-2-1. This amount was not again reallocated.

5. the Company allocated the revenue shortfall associated with the residential low income discount rate (20%) to all other rate classes based on the ratio of each class' distribution rate base.[53]

It should be noted that Bay State plans to file for recovery in its upcoming Peak CGA/LDAC any post test year increased costs incurred as a result of higher participation rates in the Company's low income discount rate resulting from the file matching program being undertaken as part of D.T.E. 01-106-B. Tr. at 2984-85.

C. Overview of Company's Approach to Rate Design

Consistent with Department precedent, Bay State proposed block rates for residential customers and flat rates for C&I customers that appropriately allocate revenue requirement, cap class bill impacts, gradually increase customer charges to low use customer classes, and simplify rate structure where appropriate, all while managing the intra-class bill impacts and avoiding or minimizing the associated intra-class subsidization. The rate design presented by Bay State is equitable and fair: it balances customer impacts while allowing for a reasonable opportunity to recover fixed costs. While simplification of rate design is an important goal, it is not the only goal. When simplification is possible in light of other goals, as is case in this proceeding with Bay State's C&I customer rates, then flat rates are feasible; but when it is not, which is the case with the residential classes, then maintaining block rates is essential.

[53] The residential low income discount revenue shortfall totals $5,953,597 and represents a 20% discount off the burner-tip costs (total bill) under the regular residential tariff rates. (See line 368 of Sch. JAF-2-1, page 14, and Sch. JAF-2-5, page 3, line 95.) The Attorney General proposes that the discount revenues be removed from base rates and recovered through the LDAC – for all gas companies in the Commonwealth. AG Br., at. 118. This issue should be resolved as a part of the Department's pending investigation in Penetration of Low Income Rates, D.T.E. 01-106-B. In the meantime, Bay State's current proposal for allocating the low income discount should be approved. See, Exh. BSG/JAF-2, p. 12.

As detailed in Mr. Ferro's testimony, Bay State designed rates in the following manner:

1. the revenue generated from the proposed customer charges were subtracted from each customer class' revenue requirement, and with the exception of the demand-based customer classes, the remaining revenue were set as a volumetric revenue target;

2. both the seasonal rate structure and customer charge levels were guided by the results of Mr. Harrison's ACOS Study;[54]

3. the existing block sizes were evaluated to determine if approximately 50% of the customers' bills terminate in the first block, and to compute the percent of therms falling in the first block. Block sizes were also evaluated by setting the blocks where approximately 50% of the customers' bills terminated in the first block and the resulting percent of therms fell in the first block;[55]

4. to ensure the block sizes struck a reasonable balance, the Company increased the Residential Heating Peak period first block size from 90 to 125 therms, and maintained the block sizes for the Off-peak period, as well as for the non-heating class' block size for both periods;

5. The Company simplified the C&I rate structure and moved to flat, or single-step, rates, minimizing variations of percentages of C&I bills ending in the first block, and moving closer to cost-based customer charges.[56]

Exh. BSG/JAF-2, at Sch. JAF-2-1.

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[54] The unit marginal costs resulting from Mr. Harrison's Marginal Cost of Service ("MCS") Study assisted in the development of the proposed second block rates, or in some cases, whether a second block was appropriate, by customer class

[55] Exh. BSG/JAF-2, at Sch. JAF-2-3 presents the results of both the current and proposed block sizes.

[56] As Mr. Ferro testified, the benefits of the simplified flat rates include: improved customer understanding, administrative ease, and an optimal level of fairness for customers and the Company with respect to the cost or revenue impact associated with usage variations, particularly due to weather. Also, considering that the proposed Customer Charge of the medium and high annual use C&I classes recover most of the customer cost component of revenue requirement the flat rate represents a reasonably accurate price for providing distribution service

D. Residential Rate Design

Bay State attempted to satisfy an important guiding principle in rate design, that the proposed rate design for all classes should produce very even/consistent and reasonably moderate percent bill impacts throughout the 25th to 50th to 75th percentiles of the annual customer use strata. See Exh. BSG/JAF-2, p. 22.

Table BSG-3 below identifies Bay State's proposed customer charges for its residential customer classes and associated percent of the cost-based charges:

TABLE BSG-3

	Mo. Charge	Approx. % of ACOS
Residential Heating:	$12.10	50%
Residential Heating Low-Income:	$ 6.25	25%
Residential Non-Heating:	$11.60	50%
Resid. Non-Heating Low-Income:	$ 6.25	25%

The residential customer charges proposed by Bay State are reasonable, because they balance the Department's regulatory policy objective to minimize bill impacts and the need to move towards cost-based rates. Bay State asks that they be approved.

The remaining revenue requirement was determined by subtracting the product of the number of test year customer charges and the proposed customer charge from the revenue requirement assigned to each customer class, with remaining revenue collected through volumetric charges. See Exh. BSG/JAF-2, at Sch. JAF-2-1, pp. 11-12. The volumetric charges for the residential customer classes were developed by first setting the second block rates as a multiple of the peak period unit marginal cost for each customer class in order to balance competing rate design goals. The second block rate was set close enough to marginal cost to provide proper price signals for customers' consumption decisions, without causing disproportionately high bill impacts for low use residential customers. The Company believes that its proposed rate structure appropriately balances the rate design goals.

The Company proposes that low-income residential customers continue to receive a 20% burner-tip discount, which results in an approximate 60% discount on distribution services. Exh. BSG/JAF-2, at 12; Exh. BSG/JAF-2 at Sch. JAF-2-5; Tr. 10, p. 1717, 1719. An iterative process was used to calculate the four residential low-income customer classes by using three components: (1) the billing determinants for the test year, (2) the proposed rate design before the inclusion of the low-income discount, and the (3) calculation of the resulting base revenues. The process was repeated until a 20% discount was achieved for both the heating and non-heating customer classes. The use of the distribution rate base allocator for the assignment of this revenue shortfall is consistent with Department policy. Bay State Gas Company, D.P.U 95-52/104; Bay State Gas Company, D.P.U. 92-111; Boston Gas Company, d/b/a KeySpan, D.T.E. 03-40. Finally, the Company proposes to reduce its Outdoor Gas Lighting Service – Rate L from the current rate is $3.32 per month per gaslight to $2.58.

E. Commercial And Industrial Rate Design

Table BSG-4 below identifies Bay State's proposed customer charges for its small and medium C&I customer classes and associated percent of the cost-based charges:

TABLE BSG-4

	Monthly Charge	Approximate % of ACOS
G/T-40/50:	$19.00	50%
G/T-41/51:	$65.00	75%

The Company proposes to maintain the same customer charge for the two Low Annual C&I classes, and the same for the two Medium Annual C&I classes.

Table BSG-5 identifies Bay State's proposed customer charges for its large and extra-large C&I customer classes and associated percent of the cost-based charges:

TABLE BSG-5

	Monthly Charge	% of ACOS
G/T-42/52:	$213.00	75%
G/T-43/53:	$781.00	100%

Through an appropriate bill impact analysis, Bay State demonstrated that these increases in customer charges will have limited impact, and there are a limited number of customers affected. No party challenged this increase. Exh. BSG/JAF-2 at Sch. JAF-2-7.

The remaining revenue requirement for the C&I customers was determined in a manner similar to the residential rate design. Exh. BSG/JAF-2, at Sch. JAF-2-1, p. 11. The volumetric rates for the small, medium and large C&I classes were established in the same manner as for the residential classes, however, ultimately Bay State was lead to the decision to design flat rates. The rate design for the extra-large volume rate (XLV) classes also reflects the fact that Bay State simplified volumetric rates by establishing flat rates for all of the C&I classes. Exh. BSG/JAF-2 at Sch. JAF-2-1 (G/T-40 and G/T-50, G/T-42 and G/T-52); Exh. BSG/JAF-2 at Sch. JAF-2-4

(G/T-40 and G/T-50, G/T-41 and G/T-51, G/T-42 and G/T-52); Exh. BSG/JAF-2 at Sch. JAF-2-6 (G/T-41 and G/T-51);

The Company proposes to maintain the existing design of the extra-large volume demand-based rate structure. Bay State Gas Company, D.P.U. 95-104 (1995).

F. Special Contract Customers

Three of the Company's five special contract customers will maintain the current rate structures because: (1) two contracts were negotiated under escalation clauses; and, (2) another is tied by contract to Bay State's firm off-system rate, which no longer exists. Tr., at 1730-33. During the course of this proceeding, Bay State amended the recovery expected from a fourth special contract customer to correct its allocation of the proposed increase. Exh. AG-22-44; Exh. BSG/JAF-2, p. 20; Exh. MP-1-04. Revenues to be received from all five of the special contract customers exceed the Company's marginal cost of providing service. Exh. AG-9-19. Since the Special Contract annual revenues clear the annual long-run marginal cost of providing service, by deducting these annual revenues, including the allocated rate increase portion, from distribution revenue requirement all firm tariff customers receive the appropriate ratemaking benefit from the Company serving these customers through lower base rates. RR-DTE-166;

Revenue Proof And Bill Impact Analysis

The Company proofed the revenue and provided a bill impact analysis for its proposed rates. Exh. BSG/JAF-2, at Sch. JAF-2-1, pp. 5-6. The final resulting class bill impacts (excluding the residential discount classes and outdoor lighting) range from an increase of 2.73%

to 7.83%. The Company also evaluated intra-class bill impacts using the 25th, 50th, and 75th percentiles, and illustrated that the percentage bill impacts within the range of these percentiles were quite even and moderate. Exh. BSG/JAF-2, at Sch. JAF-2-6, pp. 2-12, 22. The Company also prepared a typical bill analyses using average monthly usage of each customer class. Exh. BSG/JAF-2, at Sch. JAF-2-7, pp. 1-8.

G. Annual Base Rate Adjustment Mechanism ("ABRAM")

The Company's proposed Annual Base Rate Adjustment Mechanism ("ABRAM") provides for annual changes to base rates applicable to firm sales and firm transportation customer classes pursuant to Bay State's proposed Performance Based Rate ("PBR") plan and the Steel Infrastructure Replacement ("SIR") program, and reflects the annualized impact of energy efficiency savings ("EES").[57] M.D.T.E. No. 63; Exh. BSG/JAF-2, at Sch. JAF-2-8. Section 5.0 of the ABRAM tariff sets forth the formula involved in calculating the annual base rate adjustment, including the three general steps taken to arrive at revised rates.

The first step is the application of the PBR price cap adjustment to the rate for the prior year exclusive of SIR revenue requirements. Next, the PBR-adjusted base rate is further adjusted to reflect the impact of EES. Lastly, the result of these calculations is increased by the amount of the SIR Base Rate. Exh. BSG/JAF-2, at Sch. JAF-2-9.

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57 The Steel Infrastructure Replacement ("SIR") program and resulting base rate adjustment is described more fully in Testimony of Messrs. Bryant (Exhibit BSG/SHB-1), Cote (Exhibit BSG/DGC-1) and Skirtich (Exhibit BSG/JES-1). The Performance Base Rate ("PBR") structure is described more fully in Exhs. BSG/SHB-1 and BSG/LRK-1.

The PBR program, which replaces Bay State's rate freeze with an incentive-based rate mechanism, includes a price cap, an earnings sharing mechanism and an exogenous cost component. The PBR mechanism also proposes to adjust base rates to reflect the annualized impact of EES therm savings associated with Bay State's delivery of its Department-approved energy efficiency programs. This adjustment is consistent with the Department's precedent regarding Lost Base Revenues ("LBR") associated with demand-side management programs and obviates the need for a separate LBR recovery mechanism.

The PBR mechanism also includes the exogenous cost component of the ABRAM, which will keep the Company whole when unforeseen cost increases or cost reductions occur that are beyond Bay State's ability to control or influence (e.g., a change in tax laws or regulations that uniquely affects the local gas distribution industry). Exogenous costs must be material in nature in order to qualify for PBR treatment: exogenous costs that have an impact that exceeds $600,000, positive or negative, are reflected in the Z factor of the PBR formula.[58]

The earnings sharing component of the PBR program provides the Company and customers with protections in the event that earnings in any given year deviate significantly from the return on equity authorized by the Department in this proceeding. If the Company's actual return on equity in a given year is more than 400 basis points above or below its authorized return on equity, the Company shall share 25% of the earnings variance with customers. If the actual return on equity is within the bandwidth, no earnings sharing shall apply.

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[58] The $600,000 threshold (i.e., test year operating revenues $481,909,253 x 0.001253) is consistent with Department precedent. Exh. BSG/JAF-2 at Sch. JAF-1-1, p. 2. <u>Colonial Gas Company</u>, D.T.E. 98-128 (1998); and <u>Berkshire Gas Company</u>, D.T.E. 01-56 (2001); <u>Boston Gas Company d/b/a KeySpan</u>, D.T.E. 03-40 (2003).

The PBR Adjustment is applied equally to all customer classes by maintaining a uniform percentage change in the average unit price for service provided to each customer class. The Company may, at its discretion, apply a non-uniform percentage PBR adjustment to the various base rate elements of an individual Rate Schedule, but no base rate element shall be increased by a percentage greater than the higher of the GDP-PI and the PBR Price Cap Adjustment, in the event that the GDP-PI is lower than the Price Cap Adjustment. RR-DTE-126.

The proposed energy efficiency adjustment is consistent with the Department's policy with respect to approved demand-side management programs to allow utilities to recover LBR associated with EES attributable to these programs. This component is necessary because the PBR price cap formula does not implicitly recognize or account for LBR that is attributable to energy efficiency therm savings during the previous year(s). Specifically, the PBR annual rate adjustment is based on the Prior Year annual revenues, which are a function of annual therm sales that reflect the reduction is sales due to EE measures. Failure to adjust for energy efficiency savings in conjunction with an indexed based PBR mechanism would perpetuate underearning.[59]

An adjustment for the impact of energy efficiency savings is equally necessary in conjunction with future PBR rate adjustments. Integrating LBR recovery with the PBR rate adjustments simplifies the current administration and oversight of the LBR recovery process, and

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[59] The Department's approvals over the last two years of exogenous cost recovery for LBR during the rate freeze reflects this principle. See Bay State Gas Company, D.T.E. 03-36; Bay State Gas Company, D.T.E. 04-57; Bay State Gas Company, D.T.E. 04-93. However, now Bay State will no longer seek to recover LBR through an independent filing mechanism.

allows for a more accurate derivation of the incremental base rate and resulting base revenue impact associated with the therm savings.

With regard to the SIR, revenue requirements associated with the SIR program's accelerated replacement of unprotected steel infrastructure are applied as an adjustment to the Company's base rates each year. The SIR base rate for the upcoming year encompasses the total revenue requirements for the SIR program based on investments made in the most recent year as well as in prior years that the mechanism was in effect. The SIR Base Rate Adjustment is applied to existing base rates consistent with the existing rate design that results from Department approval of new rates in this case.

As Mr. Ferro testified, the SIR program revenues that will be included in the annual base rate adjustment tariff are determined each year in a manner that is consistent with traditional rate base-related ratemaking.[60] The SIR program rate base only includes accelerated gross plant investments in infrastructure improvement activities. The value of non-accelerated SIR-related gross plant investments as described by Mr. Cote, is subtracted from the total SIR-related plant investments each year to determine the amount that is included for recovery through the SIR base rates. The allowable SIR revenues will also reflect any reduction to test year O&M expense levels associated with fewer corrosion leak repairs occurring during a given SIR program year. Exh. BSG/JES-1 at Sch. JES-17. Bay State's proposal includes recovery of the carrying costs of

60 See Section 9.6 of the ABRAM tariff for the SIR revenue requirements formula (i.e., equals the sum of the pretax return on the SIR program rate base, depreciation expense, property taxes and carrying costs calculated for the duration of the period from the time plant is placed in service until the associated revenue requirements are recovered through rates).

the investment. Exh. BSG/SHB-1, pp. 36-43. Because the billing determinants each year, reflecting EES, are divided into a revenue requirement to derive SIR base rates, it is not necessary to adjust for therm savings associated with the Company's energy efficiency programs.

Consistent with Department precedents, the Company used billing determinants in its base rate adjustment calculations that were based upon the actual throughput volumes and customer counts, by rate element, for the previous calendar year, normalized for weather variances that occurred during the calendar year. Boston Gas Company, D.T.E. 03-40 at 10 (2003). It is Bay State's proposal to update billing determinants each year based on normalized current data. The average unit price for each Rate Schedule is changed each year under the PBR program in accordance with the formula set forth in Section 7.3 of the ABRAM.

Bay State proposes that its annual base rate adjustment take effect after an annual filing with the Department on or before June 1st of each year beginning in 2006. The annual filing will contain revised tariff sheets necessary to implement base rate changes effective November 1st.[61] Bay State believes this method will be a cost effective and administratively efficient manner of addressing the expected earnings erosion that will occur with the SIR capital expenditures on an annual basis.

[61] The revised tariff sheets will include a revised summary rate adjustment table to replace the one contained in M.D.T.E. No. 63, beginning at page 17 as well as replacement sheets for each firm rate schedule reflecting the adjusted base rates. Supporting schedules that provide a step-by-step calculation of each of the base rate adjustments reflected in the ABRAM will also be provided.

H. Response to Attorney General

1. Customer Charges

The Attorney General argues that the Company's proposed heating and non- heating residential and small business low load factor customer charge increases should be mitigated. AG Br., p. 115-116, fn. 60. He argues the Company's proposed increases to these customer charges represent too high an increase in the distribution service portion of the bill (excluding all adjustment clause charges). Id.

Bay State notes that the Attorney General correctly recognizes that Bay State's proposal is consistent with Department precedent. AG Br., p. 116, fn 59, citing Boston Gas Company, D.T.E. 03-40, p. 386. The proposed customer charges provide for a gradual movement towards a cost-based charge while resulting in reasonable bill impacts to most customers, particularly from the 25th to 75th percentiles. Thus, they are equitable and fair. In addition, Bay State's proposed customer charges still only recover 50% of the customer component of revenue requirement. Further, lowering the proposed customer charge increases would create higher bill impacts to higher use customers within the class. Also, lowering the customer charge to Low Annual Use C&I classes could make flat rates less effective in terms of intra-class bill impacts and reasonable price signals. Lastly, flat rates recover more of the customer costs through the customer charge.

2. Residential Rate Design

The Attorney General believes Bay State should implement a flat rate design for the residential classes similar to that proposed for C&I customers. AG Br., p. 117. Bay State disagrees: the winter unit marginal cost is substantially lower than the average volumetric rate for residential, thus not conducive to flat rates providing reasonable price signals. Price signals are very important for residential customers who do not generally have sophisticated knowledge about energy markets and do not have as many competitive options as C&I customers. The Attorney General's claim that a flat residential rate mitigates the impact of a distribution rate increase when peak gas prices take effect is not accurate. In order to mitigate or offset bill impacts caused by higher gas prices, the customer charge should increase, and the rate design should ensure the head block is priced higher than the tail block price: just the opposite of averaging the head/tail block price to set flat rates.

XIV. CONCLUSION

Wherefore, for all the reasons set forth in this Initial Brief, Bay State Gas Company respectfully requests that the Department of Telecommunications and Energy grant Bay State's request for rate relief and allow the other rate modifications requested, and grant all such other relief as it shall deem just and proper.

Respectfully submitted,

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